AD-A113 947

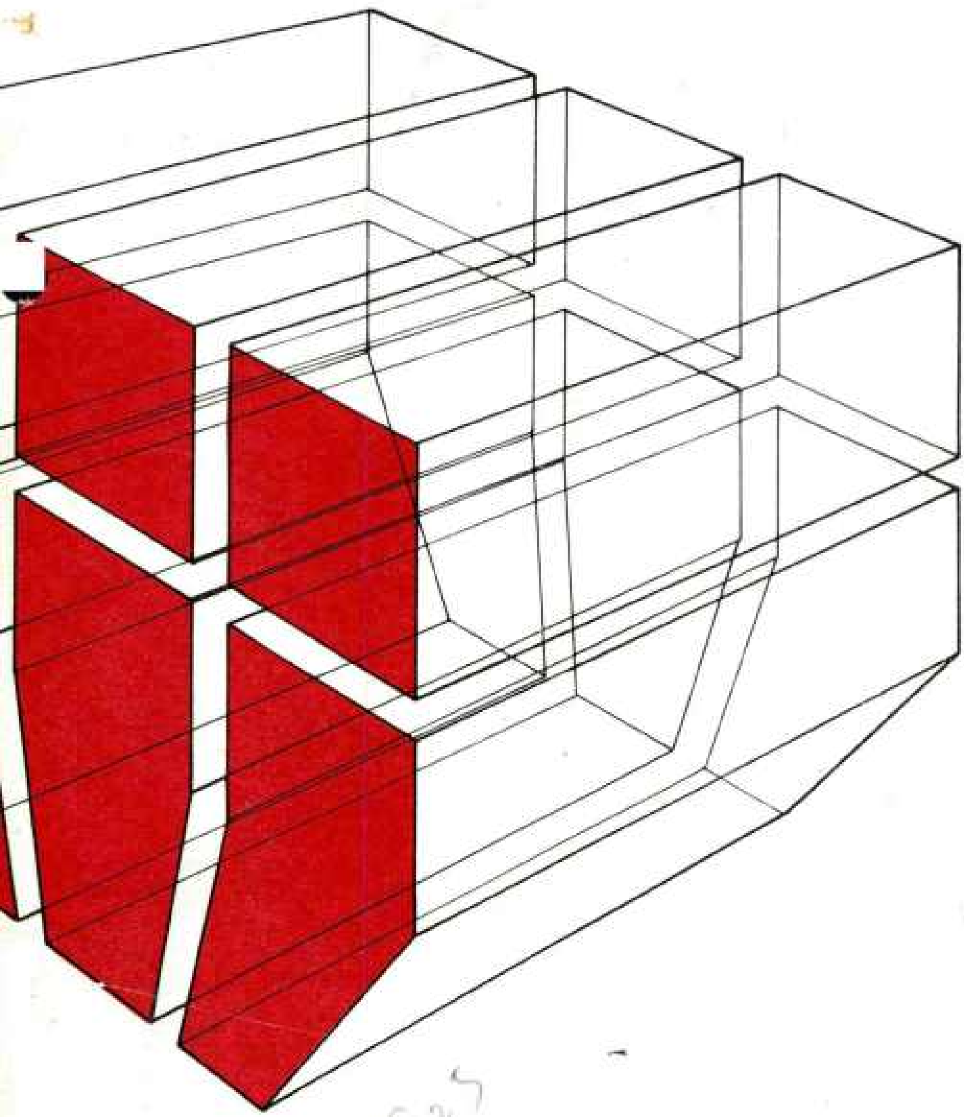
construction engineering research laboratory

United States Army Corps of Engineers
...Serving the Army
...Serving the Nation

TECHNICAL REPORT E-176
March 1982

AD A-113 947

CONVERSION OF ARMY HEATING PLANTS TO COAL : THREE CASE STUDIES



by
R. Singer
A. Collishaw

Approved for public release; distribution unlimited.

USER EVALUATION OF REPORT

REFERENCE: Technical Report E-176, *"Conversion of Army Heating Plants to Coal: Three Case Studies"*

Please take a few minutes to answer the questions below, tear out this sheet, and return it to CERL. As a user of this report, your customer comments will provide CERL with information essential for improving future reports.

1. Does this report satisfy a need? (Comment on purpose, related project, or other area of interest for which report will be used.)

____

____

____

2. How, specifically, is the report being used? (Information source, design data or procedure, management procedure, source of ideas, etc.)____________________________________

____

____

3. Has the information in this report led to any quantitative savings as far as man-hours/contract dollars saved, operating costs avoided, efficiencies achieved, etc.? If so, please elaborate. ____

____

____

4. What is your evaluation of this report in the following areas?

   a. Presentation: ____________________________________

   b. Completeness: ____________________________________

   c. Easy to Understand: ________________________________

   d. Easy to Implement: ________________________________

e. Adequate Reference Material: ______________________________

f. Relates to Area of Interest: ______________________________

g. Did the report meet your expectations? ____________________

h. Does the report raise unanswered questions? _______________

i. General Comments (Indicate what you think should be changed to make this report and future reports of this type more responsive to your needs, more usable, improve readability, etc.) ____________________

____

____

____

____

5. If you would like to be contacted by the personnel who prepared this report to raise specific questions or discuss the topic, please fill in the following information.

Name: ____________________________

Telephone Number: ____________________________

Organization Address: ____________________________

____

____

6. Please mail the completed form to:

Department of the Army
CONSTRUCTION ENGINEERING RESEARCH LABORATORY
ATTN: CERL-SOI
P.O. Box 4005
Champaign, IL 61820

UNCLASSIFIED

SECURITY CLASSIFICATION OF THIS PAGE *(When Data Entered)*

REPORT DOCUMENTATION PAGE		READ INSTRUCTIONS BEFORE COMPLETING FORM
1. REPORT NUMBER CERL-TR-E-176	2. GOVT ACCESSION NO.	3. RECIPIENT'S CATALOG NUMBER
4. TITLE *(and Subtitle)* CONVERSION OF ARMY HEATING PLANTS TO COAL: THREE CASE STUDIES		5. TYPE OF REPORT & PERIOD COVERED FINAL 6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s) R. Singer A. Collishaw		8. CONTRACT OR GRANT NUMBER(s)
9. PERFORMING ORGANIZATION NAME AND ADDRESS U.S. ARMY CONSTRUCTION ENGINEERING RESEARCH LABORATORY P.O. Box 4005, Champaign, IL 61820		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS 4A762731AT41-G-007
11. CONTROLLING OFFICE NAME AND ADDRESS		12. REPORT DATE March 1982 13. NUMBER OF PAGES 203
14. MONITORING AGENCY NAME & ADDRESS *(if different from Controlling Office)*		15. SECURITY CLASS. *(of this report)* Unclassified 15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT *(of this Report)*

Approved for public release; distribution unlimited.

17. DISTRIBUTION STATEMENT *(of the abstract entered in Block 20, if different from Report)*

18. SUPPLEMENTARY NOTES

Copies are obtainable from the National Technical Information Service
Springfield, VA 22151

19. KEY WORDS *(Continue on reverse side if necessary and identify by block number)*

coal
boilers
heating
conversion

20. ABSTRACT *(Continue on reverse side if necessary and identify by block number)*

This study reports the results of three site-specific engineering studies to convert main heating plants to coal as a fuel. The Army installations examined were Redstone Arsenal, AL; Picatinny Arsenal, NJ; and the U.S. Military Academy (West Point) in New York. Each of these installations formerly fired coal and was converted to fuel oil about two decades ago.

DD FORM 1 JAN 73 1473 EDITION OF 1 NOV 65 IS OBSOLETE

UNCLASSIFIED

SECURITY CLASSIFICATION OF THIS PAGE *(When Data Entered)*

BLOCK 20 CONTINUED

Researchers considered application of both current and advanced coal systems, which included direct combustion (either in suspension or on a grate), production and firing of low- and high-Btu coal-derived gas, and production and use of coal-derived liquid fuel. Both rehabilitation and replacement of plants were considered. Capital investment and annual operating costs are reported for alternative conversions:

Redstone Arsenal -- rehabilitation and conversion of two plants versus one new coal-fired central plant.

Picatinny Arsenal -- rehabilitation of existing boilers to fire gas produced by a new nearby gasification plant, versus new stoker-fired boilers, versus a new fluid bed combustor (FBC).

West Point -- rehabilitation of existing boilers to fire gas produced by a new plant about 2 mi (3000 m) from the existing plant, versus a new FBC with steam piped to the distribution system 2 mi (3000 m) away.

The report concludes that all three installations should change from fuel oil to coal based on the economics presented. A summary is given below, where CI is the capital investment; LCC is the life-cycle cost, including the CI for 25 years; PP is the cost of continuing the present practice, with all costs given in millions of 1985 dollars:

Location	CI	LCC	PP
Redstone Arsenal	19	78	260
Picatinny Arsenal	52	167	380
West Point	61	156	210

The report recommends, given these costs, that Redstone Arsenal rehabilitate and reconvert its boilers to fire coal, that Picatinny Arsenal build a new fluid bed boiler plant to replace the existing oil-fired plant, and that West Point build at a new location a coal-fired plant to replace the existing plant.

FOREWORD

This research was performed by the U.S. Army Construction Engineering Research Laboratory (CERL) for the Directorate of Military Programs, Office of the Chief of Engineers (OCE), under Program Element 6.27.31A, "Research and Investigation Program"; Project 4A762731AT41, "Military Facilities Engineering Technology"; Task G, "Military Energy Technology"; Work Unit 007, "Waste-Derived Fuel (WDF)." The OCE Technical Monitor was Mr. B. Wasserman, DAEN-MPO-U. Mr. A. Collishaw of the CERL Energy Systems Division (ES) was the Principal Investigator.

Appendix A was prepared by SCS Engineers, Inc. SCS personnel directly involved in the study were Mr. John P. Woodyard, Project Manager, Mr. Robert L. Yust, Project Engineer, and Mr. Brian W. West, Project Engineer. Close coordination and valuable assistance were provided by the Facilities Engineering Department of Redstone Arsenal, particularly Mr. Charles Rollins and Mr. Ron Harmon. Appendices B and C were prepared by Pope, Evans, and Robbins.

Mr. R. G. Donaghy is Chief of ES. COL L. J. Circeo is Commander and Director of CERL, and Dr. L. R. Shaffer is Technical Director.

CONTENTS

FIGURES

TABLES

TABLES (Cont'd)

CONVERSION OF ARMY HEATING PLANTS
TO COAL: THREE CASE STUDIES

1 INTRODUCTION

Background

The Army Energy Plan sets goals for the reduction of use of energy by the Army.[1] Two of these goals relate to Army facilities: (1) by FY85 energy consumption in facilities operations must be reduced by 20 percent from the FY75 level, and an additional 20 percent by the year 2000; (2) the use of natural petroleum fuels must be reduced 75 percent by the year 2000. To meet this challenge, it is expected that some Army installation heating and power plants now firing gas or oil will be converted to coal. The U.S. Army Construction Engineering Research Laboratory (CERL) has published general technical and economic guidance on applicable coal technologies which district engineers and facilities engineers may use in developing installation coal-use projects. This information was published in 1979 as CERL Interim Report (IR) E-148.[2]

IR E-148 is general and is intended to cover a broad scope of Army-wide coal conversion applications. Accordingly, it is not concerned with coal conversion problems and other considerations which are site-specific and must be dealt with on an installation-by-installation basis.

Research at individual installations was needed (1) to "field check" the contents of IR E-148 by actual use, and (2) to provide information for determining the economics of the site-specific coal conversion proposals.

Objective

The objective of this study was to determine whether additional useful information on coal conversion could be obtained by applying IR E-148 guidance to proposed site-specific coal conversions, and thereby to recommend coal conversion strategies for the three sites studied.

Approach

Three Army installations that had once fired coal in their heating plants were selected for site-specific engineering study: Redstone Arsenal, AL; Picatinny Arsenal, NJ; and the U.S. Military Academy (West Point) in New York. The studies were completed by engineering firms experienced in the design of heating plants. The contractors made site visits to gather the necessary

---

[1] Army Energy Plan (Headquarters, Department of the Army, February 1978 and August 1980).

[2] S. A. Hathaway, M. Tseng, and J. S. Linn, Project Development of Guidelines for Converting Army Installations to Coal Use, Interim Report E-148/ADA068025 (U.S. Army Construction Engineering Research Laboratory [CERL], March 1979).

information to propose alternative methods for converting the heating plants to coal. They were to consider application of both current and advanced coal systems which included direct combustion (either in suspension or on a grate), production and firing of both low- and high-Btu coal-derived gas, and production and use of coal-derived liquid fuel. Both rehabilitation and replacement of plants were considered. Capital investment and annual operating costs of the alternative conversions were estimated.

The contractors were to use the material presented in IR E-148 as part of their work in preparing the coal conversion alternatives for each installation.

Scope

This report presents the site-specific findings of the three studies (see Appendices A, B, and C) and comments on IR E-148. The findings include technical and economic information for the coal conversion alternatives as they apply to the sites.

Chapter 2 discusses the conversion alternatives considered at each of the three sites. Economic considerations are stated, and the capital investment, annual operating costs, and Life Cycle Costs (LCC) are given.

It is important to note that while the economics presented in the body of this report are based on the data in the appendices, changes were made for clarity. For instance, labor at $25,000 per man-year, and fuel oil at $0.80 (1979 dollars) was used at each site.

Chapter 3 presents economic data which compares and ranks the three sites as potential conversion locations.

Chapter 4 discusses suggested improvements to IR E-148.

Conclusions are given in Chapter 5.

2 CONVERSION ALTERNATIVES AT THE THREE SITES

The contractors provided detailed construction cost estimates and annual operating cost estimates. This report gives those costs in 1985 dollars, since a decision to convert to coal use would be for program year FY84, with 1985 dollars as the midpoint of construction. The savings would not begin to accrue until FY87.

Staffing is addressed as part of each alternative. In all cases, the conversion from fuel oil to coal requires a larger staff. Solid fuel handling is an added function that requires personnel. When coal gasification is considered as an alternative, the increases are even greater because the gasification plant as well as the boiler plants must be manned.

Case I: Redstone Arsenal

Description of the Existing Heating Plants at Redstone Arsenal

Two main boiler plants -- No. 3264 and No. 4725 -- account for 84 percent of Redstone's nameplate capacity. Both are about 40 years old. Plant 3624 is equipped with four 60,000 lb/hr (18 MW) boilers, while Plant 4725 has four 100,000 lb/hr (29 MW) boilers. Both plants presently operate on fuel oil, but Plant 4725 was originally designed for pulverized coal, and Plant 3624 originally used underfire vibrating grates. Plant 3624 was rebuilt in 1960; new boiler tubes were installed. Plant 4725 has never been rebuilt and is now near the end of its working life. Figure 1 shows the location of these two main steam plants at Redstone Arsenal.

Twenty-four additional gas- or oil-fired steam boilers at Redstone Arsenal account for 16 percent of the nameplate capacity. These boilers are at approximately 10 locations on the installation.

Four alternatives were considered for coal conversion:

1. A new coal-fired, central steam plant serving the two areas now served by two plants.

2. New coal-fired plants, one at each existing location.

3. A new coal liquefaction or gasification plant.

4. Rehabilitation and reconversion of the existing plants.

A more detailed description of each of these alternatives follows (also see Appendix A).

New Coal-Fired Central Plant

Other studies have examined the alternative of having one central plant at Redstone Arsenal.[3] The proposed location is equidistant from the existing steam distribution networks of Plants 4725 and 3624 (see Figure 1). About 1 mi (1800 m) of new steam line would be needed to tie the new facility to the existing distribution systems. The proposed location is presently undeveloped and would require site work. It is expected that the new central facility would use two pulverized coal-fired boilers with a backup oil-firing capability.[4] One oil-fired boiler also would be included. All three boilers would be rated at 192,000 lb (56 MW) of steam per hour. As sized, only one of the three boilers would be required at any one time. SCS Engineers, Inc., took a different approach than Black and Veatch and based this alternative on two spreader-stoker fired boilers at 175,000 lb (51 MW) of steam per hour.

Two New Coal-Fired Plants, One at Each Existing Location

With the second alternative, new coal-fired plants would be built next to the existing 40-year-old plants. At Plant 4725 there would be three 100,000 lb/hr (29 MW) traveling-grate-type stokers to replace the existing stokers. And at Plant 3624, there would be two 100,000 lb/hr (29 MW) traveling grate stokers to replace the four boilers.

A New Coal Liquefaction, Gasification Plant

The third alternative would provide a liquefaction or gasification plant which would produce a fuel suitable for use in the existing boilers. There are several technologies available; of those, the most advanced is the Koppers-Totzek system, which would be used. Ducting, burner, and control modifications would be needed to fire the approximately 300 Btu/cu ft (11 MJ/m^3) of gas which would be prepared by this gasifier. A derating of about 40 percent from oil rating, or nominally 15 percent from coal rating, would be required. Also, due to their age and condition, Plants 3624 and 4725 would have to be rehabilitated before coal, gas, or oil could be used.

Rehabilitation and Reconversion of Existing Steam Plants

The existing plants could be rehabilitated and converted to fire coal again. Since they were originally designed and built to burn coal, the sizing and combustion of the coal should remain as designed. Converting both facilities to coal should be relatively simple.

Since the boilers are about 40 years old, a significant amount of rehabilitation would be needed. For this analysis, it is assumed that all boiler internals would have to be replaced, and that the auxiliary plant would have to be completely overhauled. In addition, at Plant 4725 a coal storage area would be required.

---

[3] Black and Veatch Consulting Engineers, Base-Wide Energy Systems Plan -- Total Energy and Selected Energy (Draft Final Report for the Mobile District Corps of Engineers, October 1979).

[4] Black and Veatch.

Preferable Alternatives

Table 1 briefly describes the advantages and disadvantages of each of the coal conversion possibilities for Redstone Arsenal.

The contractor proposed that rehabilitation of the two existing plants and one new coal-fired central plant is the most practical and economical of the four alternatives. A cost estimate was done for this option. The two existing plants have a staff of 10. Tables 2, 4, 5, and 6 give the annual operating and capital costs of the alternative. Table 7 summarizes the capital and operating costs associated with each alternative. (Table 3 presents multipliers used to convert annual costs to 25-year, present-value costs.) Note that in 1985 dollars, the annual cost for the rehabilitation/reconversion alternative would be \$3.35 million and that the first cost -- that is, the capital investment required for the rehabilitation -- would be \$19.0 million; the staff would increase to 28. This compares to an annual cost of \$2.2 million and a first cost of \$34.0 million (1985 dollars), with a staff increase to 22, for the new coal-fired central plant alternative.

Case II: Picatinny Arsenal

Description of the Existing Plant

Picatinny Arsenal power plant has three boilers which operate at 420 psig (202 000 Pa) and 650 $^{\circ}$F (343.3 $^{\circ}$C). Two of the boilers, manufactured in 1943, are rated at 160,000 lb/hr (47 MW); these were originally converted from pulverized coal to oil or gas. A third boiler, manufactured in 1971, is rated at 20,000 lb (6 MW) of steam per hour; this is a packaged oil-fired unit. The power plant also has three turbine generators. Two are rated at 3000 kW and one at 1500 kW. Table 8 gives the present and projected steam and fuel usage for this plant.

Conversion Alternatives

Economic studies were done for three alternatives at Picatinny Arsenal:

1. A gasification plant with conversion of the existing boilers to fire the gas. Staffing would change from 50 to 75.

2. New stoker-fired boilers with flue gas desulfurization included. Staffing would change from 50 to 65.

3. A fluid bed combustion boiler with baghouse. Staffing would change from 50 to 64.

Complete descriptions of these alternatives are in Appendix B. Tables 9 through 14 give the capital and operating costs for each alternative in 1985 dollars. A summary of the alternatives is given in Table 15.

Case III: U.S. Military Academy (West Point)

Description of Existing Facilities

The main boiler plant, No. 604, has a capacity of 598 million Btu/hr (175 MW). The plant operates on no. 6 fuel oil. Table 16 shows the steam and fuel requirements (also see Appendix C).

Discussion of the Options for West Point

Several options were considered at West Point: retrofit or conversion of the existing plant to fire coal; low-, medium-, or high-Btu gas; liquefaction; or a new coal-fired plant. It is not possible to actually convert the existing plant to burn coal at West Point. The main problem is that since the plant was converted several years ago from coal to oil, buildings were added to the area and take up the space originally occupied by the coal handling system. Therefore, there is not enough room now to bring in coal to the site. The second problem is also related to space availability. At the existing site, there is no room to build the air pollution control devices that would be required for reconversion to coal-firing. For these reasons, the actual conversion or retrofit to coal of the existing boilers was dropped as an alternative. It was then decided that capital and annual cost estimates would be provided for only two alternatives: (1) use of a fluid bed boiler at a remote site, with the steam piped to the existing distribution network, and (2) construction of a gasification plant at a remote site, with the new gas piped to the existing boiler. Figure 2 indicates the location of the existing plant and the proposed remote plant. Note that the existing boiler would have to be retrofitted to fire this gas. The staffing requirements will change if the plant is converted to coal. Tables 17 through 20 show the capital and operating costs (in 1985 dollars) of each of the alternatives. Table 21 summarizes the data.

3 DISCUSSION AND COMPARISON OF CASE ALTERNATIVES

The data in Tables 22 and 23 permit comparison of the alternatives discussed in Chapter 2, and provide a means of selecting the location to be converted first.

Note that in all cases, the staffing requirements increase. The largest increase occurs when both a gasification and a boiler plant are used.

Four economic criteria are often used in selecting among alternatives: the lowest life-cycle cost (LCC),* the highest savings-to-investment ratio (SIR), the lowest straight line years-to-payback and the most favorable energy-to-cost (E/C) ratio.** Usually, there is no conflict in these criteria. Note, however, in Case II below, and as shown in Table 23, the most favorable SIR (gasification) has the highest (least favorable) LCC.

Case I

Redstone Arsenal has the most favorable E/C ratio, LCC, SIR, and years to payback.

Case II

Picatinny Arsenal has the next most favorable E/C and SIR with gasification technology. In this case, the LCC should be used as a basis for selection. If SIR were used, then gasification would cost $30 million more, in present value, over a 25-year life of the project. The LCC of stokers and fluid bed boilers is nearly the same, so the selection should be based on lowest capital investment and shortest years to payback -- fluid bed boilers.

Case III

For West Point, the E/C and LCC should be used as a basis for decision. The LCC for fluid bed boilers is nominally $25 million less than that for the gasification plant. It also has the most favorable years to payback.

---

* LCC is the total cost of the system (fewer sunk costs). It includes the capital investment plus the operating costs over the 25-year economic life of the project.

**E/C ratio is a number obtained by dividing the annual energy saved, in MBtus, by the capital investment in thousands of dollars. This number represents the energy saved per unit of investment.

4 IMPROVEMENTS TO IR E-148

The contractors were asked to offer specific comments that would make CERL IR E-148 more useful. The following suggestions were made:

1. A number of constraints associated with the installation and operation of coal-fueled heating plants affect the usefulness of these operations. Many of these constraints are already addressed in IR E-148. However, the contractors suggested some additional limitations. For example, regulation of air pollutant emissions is one limiting parameter. In the South Coast Air Basin of California, coal conversion probably would not be allowed, regardless of the control equipment used. And if local authorities will not permit the use of coal, there is no point in spending time and money to explore that alternative. A listing of the suggested constraints is given in Table 24.

2. Cost data for fluid bed combustion boilers could be added so that the report user could compare fluid bed boilers with the other alternatives presented.

3. In addition to the costs given, unit costs would be helpful -- such as dollars per pound or dollars per cubic feet per minute. An example of such unit costs is given in Appendix B, Table 4-1.

5 CONCLUSIONS

1. The contractors' suggestions for improving IR E-148 were not major; the report need not be updated. As CERL completes work on fluid bed combustion and on examples of coal conversions, the results (including the costs associated with fluid bed combustion and completed coal conversions) will be published.

2. At Redstone Arsenal, Picatinny Arsenal, and West Point, the cost of continuing to burn fuel oil far exceeds the cost of changing to coal as a fuel. (Table 25 summarizes the LCCs.)* Therefore, the installations should initiate Military Construction projects to convert their facilities to burn coal. The conversions should be made in the following order, which is based on the most to least favorable E/C ratio:

a. Redstone Arsenal should rehabilitate and reconvert its existing plants to fire coal.

b. Picatinny Arsenal should build a new coal-fired plant. The accuracy of the estimates does not allow a technology to be selected on the basis of LCC economics. However, if selection is based on first cost, fluid bed boilers should be chosen.

c. West Point should build a new coal-fired fluid bed plant.**

---

* The project costs are given in 1985 dollars, with the operating costs present valued to 1985, the mid-point of construction. The capital investment of the present practice is not included in the LCC because it is a sunk cost.

**This conclusion is reached because the type of plant is economically feasible using present Army Energy Conservation Investment Program (ECIP) criteria. The contractor (see Appendix A) used differing criteria and reached a different conclusion; i.e., that conversion is not economical.

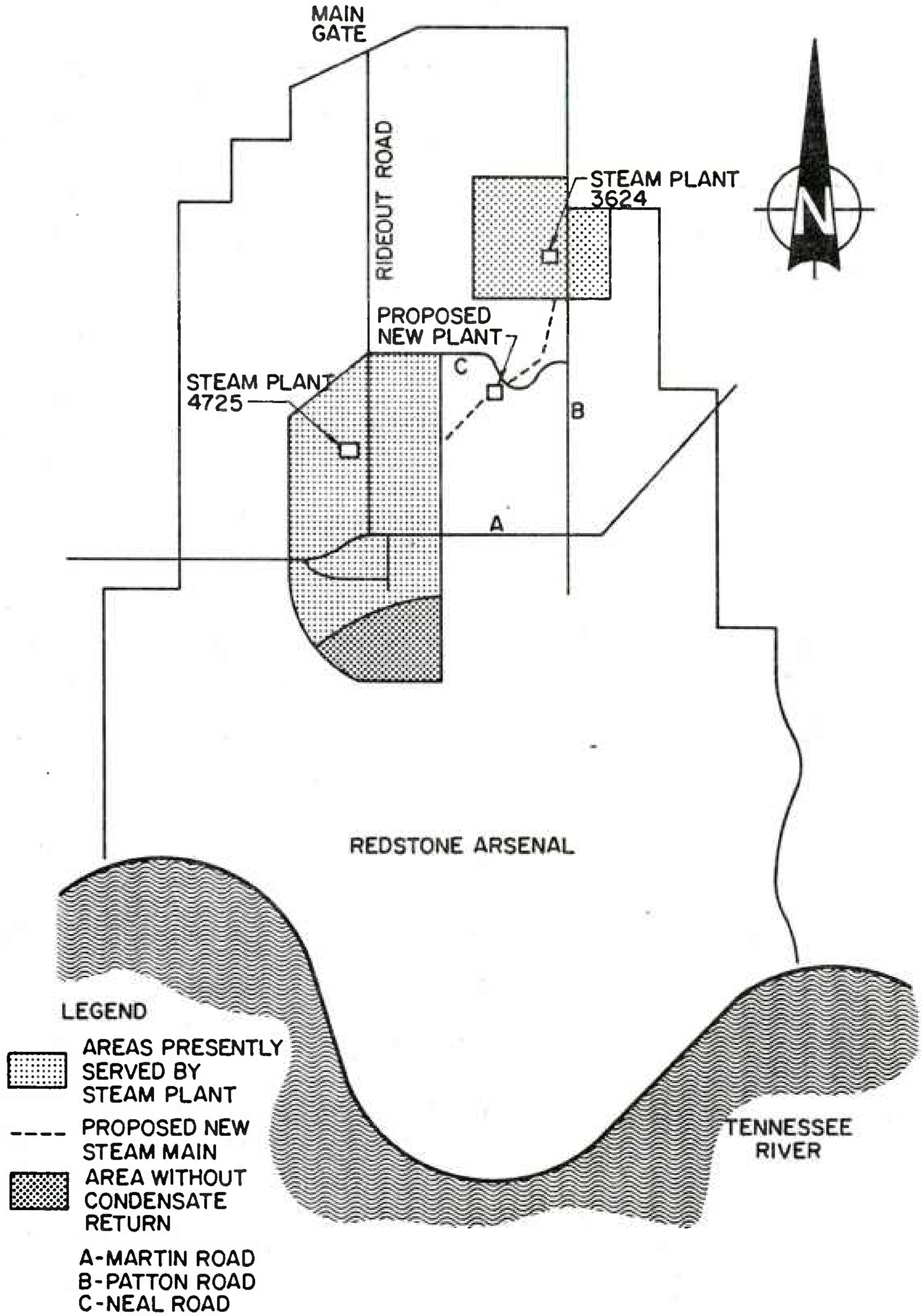


Figure 1. Redstone Arsenal, steam generation and use.

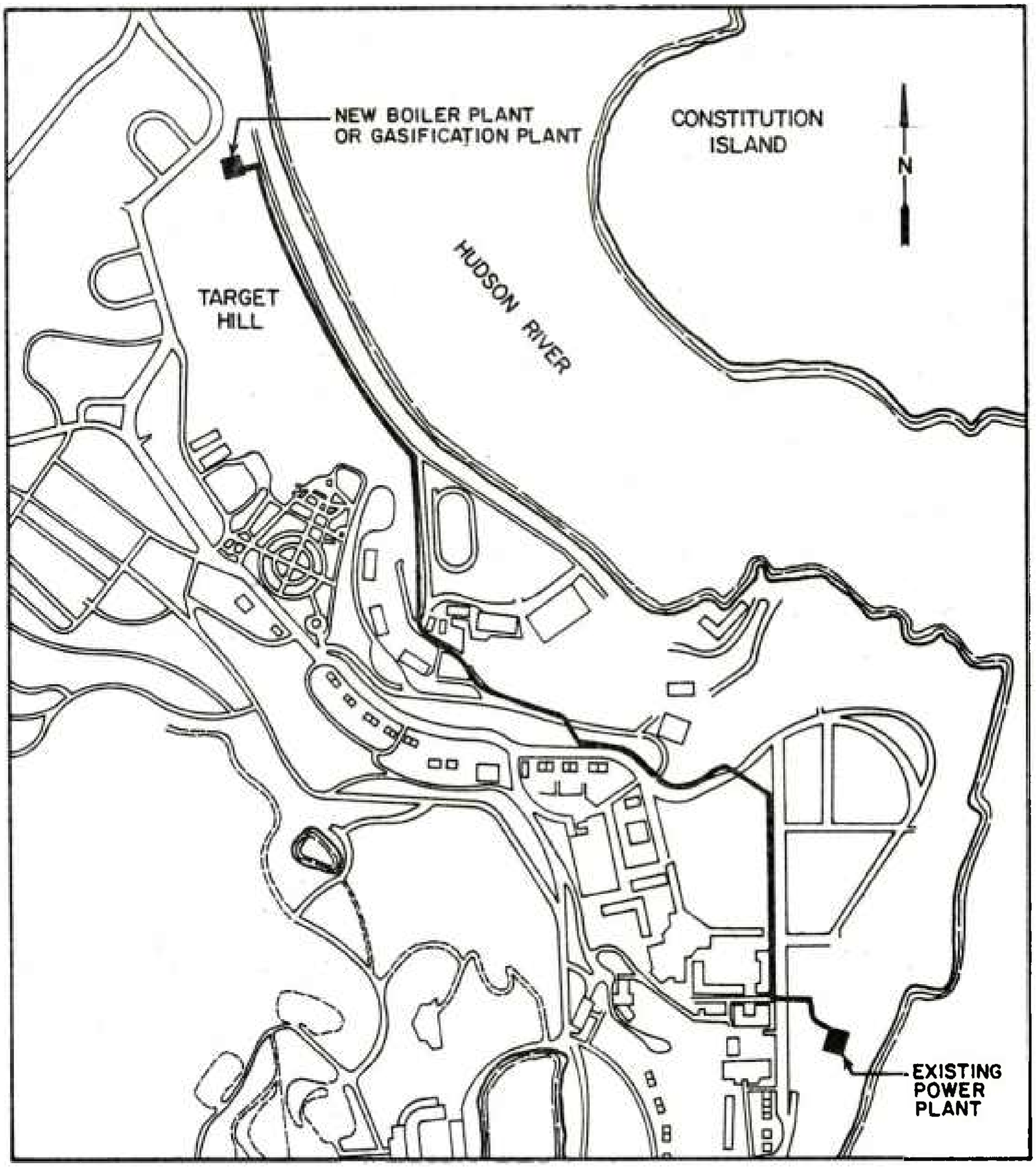


Figure 2. Express main layout for steam or gas.

Table 1

Redstone Arsenal -- Coal Conversion Alternatives

Alternative	Advantages	Disadvantages
New coal-fired central steam plant	o Developed technology o Credible cost forecast o Minimum new distribution system development o Potential for use of alternate fuels	o Large first cost o No use of existing energy equipment
Rehabilitation and reconversion of existing steam plants	o Maximum use of existing equipment o Lower first cost o No new site required	o Increased recurring costs o Difficult to accurately predict first costs
New coal liquefaction/ gasification plant	o Use of existing boiler equipment o Greater environmental acceptance	o Large first cost o Undeveloped technology o Need to rehabilitate existing boiler equipment o Low acceptance by Redstone personnel
New coal-fired satellite plants	o Additional redundancy o No new distribution system development required o Lower recurring costs vs. rehabilitation	o Loss of economies of scale o Large first costs o Greater recurring costs than central plant

Table 2

Redstone Arsenal -- Rehabilitation/Reconversion Capital Cost Estimate

Item	Plant 4725 (Cost, 1980 Dollars)	Plant 3624 (Cost, 1980 Dollars)
Fuel delivery	50,000	55,000
Fuel storage	130,000	98,000
Fuel handling	693,000	416,160
Boiler conversion	6,220,000	4,716,000
Residue handling	703,000	491,400
Air pollution control	246,000	155,000
Start-up	35,000	35,000
Shakedown	83,000	83,000
Grand total	8,160,600	6,049,560
	Plant 3624	6,049,560
	Plant 4725	8,160,600
	Total 1980 dollars =	14,210,160 x 1.338
	Total 1985 dollars =	19,013,000

Table 3

Multipliers for 25-Year, Present-Value Cost

1. 25-Year Present Value (PV) Labor = Labor (1980) x $(1.056)^{7*}$ x 9.524**
   25-Year PV Labor = Labor (1980) x 13.95

2. 25-Year PV Maintenance = Maintenance (1980) x $(1.06)^{7}$ x 9.524
   25-Year PV Maintenance = Maintenance (1980) x 14.32

3. 25-Year PV Coal = Coal (1980) x $(1.10)^{7}$ x 14.777
   25-Year PV Coal = Coal (1980) x 28.80

4. 25-Year PV Electric = Electric (1980) x $(1.13)^{7}$ x 18.049
   25-Year PV Electric = Electric (1980) x 42.46

5. 25-Year PV Fuel Oil = Fuel Oil (1980) x $(2.502)^{7}$ x 20.05
   25-Year PV Fuel Oil = Fuel Oil (1980) x 50.17

Note:
*1.056 is the annual escalation rate for labor.
**9.524 is the differential inflation rate for labor; both rates were taken from the Inclosure to a multiple letter from DAEN-FEU, Subject: "Energy Conservation Investment Program (ECIP) Guidance," 7 November 1977. The values for maintenance, cost, etc., were taken from the same source.

Table 4

Redstone Arsenal -- Recurring Cost Summary -- Rehabilitation/Reconversion Alternative

Item	Quantity	Unit Cost	Annual Cost ($\$10^3$/yr)	25-yr) PV**
		Plant 4725		
Labor	15	25,000/man-year*	375.0	5228
Coal	19,500 tons	$49/ton	955.5	27,518
Maintenance	5000 hr	$11/hr	55.0	788
Electric	1.08×10^6 kWh	$0.035/kWh	38.0	686
Water	10.0×10^6 gal	$0.21/gal	21.2	296
Total			1444.7	34,516
		Plant 3624		
Labor	13	25,000/man-year*	325.0	4513
Coal	13,260 tons	$49/ton	649.7	18,711
Maintenance	3800 hr	$11/hr	41.8	599
Electric	731,500 kWh	$0.035/kWh	25.6	462
Water	8×10^6 gal	$0.21/gal	16.9	236
Total			1,059.0	24,521
		Grand total 1980 dollars =	2503.7	
		Grand total 1985 dollars =	3350.0	59,040

*Average yearly expense: wages plus fringe benefits.
**The 25-year present value, as of the first year of benefit -- in this case 1986. It is obtained by multiplying the annual costs (in 1980 dollars) times the values given in Table 3.

Table 5

Redstone Arsenal -- New Coal-Fired Central Steam Plant
Capital Cost Summary

Item	Cost ($)
Boiler system (2 ea. 175,000 pph)	21.5×10^6
Site preparation and grading*	180,000
Access roads*	25,000
Ash disposal	800,000
Coalyard preparation*	275,000
Water supply	175,000
Steam distribution	680,000
Utilities	300,000
Boiler house	1.5×10^6
Total, in 1980 dollars	25.4×10^6 x 1.338
Total, in 1985 dollars	34.0×10^6

*1980 Dodge Guide (Public Works and Heavy Construction) (McGraw-Hill Information Service Company, 1980).

Table 6

Redstone Arsenal -- Recurring Cost Summary --
New Coal-Fired Central Steam Plant

Item	Quantity	Unit Cost	Annual Cost ($\$10^3$/yr)	25 yr PV**
Labor	22	25,000/man-year*	550	7667
Coal	32,760 tons	$49/ton	1605	46,220
Maintenance	2200	$11/hr	24.2	347
Utilities	1.63×10^6 kWh	$0.035/kWh	57.0	2420
Water	8.5×10^6 gal	$0.21/kgal	18.0	250
		Total in 1980 dollars =	2,254.2	
		Total in 1985 dollars =	4,131.0	56,910

*Average yearly expense: wages plus fringe benefits.
**The 25-year present value, as of the first year of benefit -- in this case 1986. It is obtained by multiplying the annual costs in 1980 dollars times the values given in Table 3.

Table 7

Summary of Conversion Alternatives for Redstone Arsenal

Alternative	Capital Cost*	Annual Cost*	Present Staff	Proposed Staff
Present oil operation	--	$13.0 million	10	Not applicable (NA)
Rehabilitate/ Reconvert	$19.0 million	$3.4 million	NA	28
New central plant	$34.0 million	$4.1 million	NA	22

*Costs are in 1985 dollars.

Table 8

Picatinny Arsenal -- Steam and Fuel Requirements

1. Steam

A. Current	
Annual	1.24×10^9 lb/year
Peak	212,000 lb/hr (62 MW)
Average	140,000 lb/hr (41 MW)
B. Projected	
Annual	1.04×10^9 lb/year
Peak	200,000 lb/hr (59 MW)
Average	120,000 lb/hr (35 MW)

2. Fuel*

	Oil	Coal
A. Current		
Annual	10,700,000 gal/yr (40 500 m^3/yr)	65,000 tons/yr (59 000 MT/yr)
Peak	1830 gal/hr (6.93 m^3/hr)	11 tons/hr (10 MT/hr)
Average	1210 gal/hr (4.58 m^3/hr)	7.3 tons/hr (6.6 MT/hr)
B. Projected		
Annual	9,000,000 gal/yr (34 000 m^3/yr)	55 000 tons/yr (50 000 MT/yr)
Peak	1730 gal/hr (6.55 m^3/hr)	10.4 tons/hr (9.4 MT/hr)
Average	1040 gal/hr (3.94 m^3/hr)	6.3 tons/yr (5.7 MT/hr)

---

*Based on fuel oil at 145,000 Btu/gal (404 kJ/m^3), and coal at 12,000 Btu/lb (28 MJ/kg).

Table 9

Picatinny Arsenal -- Summary of Capital Costs for
Gasification Plant, Boiler Retrofit,
Existing Turbine Generators

Line Item	Total
1. Coal delivery and handling	
Railcar unloading building	820
Coal preparation building	158
Coal storage pile	1379
2. Process and boiler plant	
Process plant	17,381
Boiler conversion	759
3. Pollution control	
Ash silos	138
4. Turbine modifications	1088
5. Yardwork, utilities, demolition, and miscellaneous	1633
Subtotal	23,356
Contingency at 15 percent	3503
Total Capital Cost	26,859
Supervision, Inspection, and Overhead (SIOH) at 5.5 percent	1477
Grand total, 1979 dollars =	28,336
Grand total, 1985 dollars =	40,190

*In thousands of dollars, costs estimated as of third quarter, 1979.

Table 10

Picatinny Arsenal -- Summary of Operating Costs for
Gasification Plant, Boiler Retrofit,
Existing Turbine Generators

Item	Total	25-yr PV**
1. Labor	1875	26,140
2. Materials	566	7890
3. Disposals	272	3790
4. Electric: System operation	160	6790
5. Coal	3929	113,200
Grand total 1979 dollars =	6,702	
Grand total 1985 dollars =	12,030	157,800

*In thousands of dollars; estimated as of third quarter, 1979.

**The 25-year present value, as of the first year of benefit -- in this case 1986. It is obtained by multiplying the annual costs in 1980 dollars times the values given in Table 3.

Table 11

Picatinny Arsenal -- Summary of Capital Costs for
Stoker Boilers, Flue Gas Desulfurization,
New Turbine Generators*

Line Item	Total
1. Coal delivery and handling	
Railcar unloading building	820
Coal preparation building	158
Coal storage pile	965
2. Boiler plant	
In-plant coal handling	756
Boilers	18,964
3. Pollution control	
Scrubber system	6239
Lime and sludge storage	802
Ash handling	297
4. Turbines	4201
5. Yardwork, utilities, demolition, and miscellaneous	1531
Subtotal	34,733
Contingency at 10 percent	3473
Total capital cost	38,206
SIOH at 5.5 percent	2102
Grand total, 1979 dollars	40,308
	1.418
Grand total, 1985 dollars	57,170

*In thousands of dollars; costs estimated as of third quarter, 1979.

Table 12

Picatinny Arsenal -- Summary of Operating Costs for
Stoker Boilers, Flue Gas Desulfurization,
New Turbine Generators*

Item	Total	25-yr PV**
1. Labor	1625	22,650
2. Materials	1127	15,710
3. Disposals	1024	14,270
4. Electric:		
System operation	175	7430
Cogeneration (savings)	(641)	(27,200)
5. Coal	2750	79,200
Grand total, 1979 dollars =	6,060	
Grand total, 1985 dollars =	9,873	112,100

*In thousands of dollars, estimated as of third quarter, 1979.

**The 25-year present value, as of the first year of benefit -- in this case 1986. It is obtained by multiplying the annual costs in 1980 dollars times the values given in Table 3.

Table 13

Picatinny Arsenal -- Summary of Capital Costs for Fluid Bed Combustion Boilers, Baghouses, New Turbine Generators*

Line Item	Total
1. Coal delivery and handling	
Railcar unloading building	820
Coal preparation building	158
Coal storage pile	965
2. Boiler plant	
In-plant coal handling	754
Boilers	18,205
3. Pollution control	
Baghouse	2598
Limestone storage	1328
Ash handling	924
4. Turbines	4201
5. Yardwork, utilities, demolition, and miscellaneous	1531
Subtotal	31,484
Contingency at 10 percent	3148
Total capital cost	34,632
SIOH at 5.5 percent	1905
Grand total, 1979 dollars =	36,537
Grand total, 1985 dollars =	51,800

*In thousands of dollars; costs estimated as of third quarter, 1979.

Table 14

Picatinny Arsenal -- Summary of Operating Costs for
Fluid Bed Combustion Boilers, Baghouses,
New Turbine Generators*

Item	Total	25-yr PV**
1. Labor	1600	22,300
2. Materials	1069	14,900
3. Disposals	331	4610
4. Electric:		
System operation	514	21,800
Cogeneration (savings)	(641)	(27,200)
5. Coal	2750	79,200
Grand total, 1979 dollars =	5623	
Grand total, 1985 dollars =	9496	115,610

*In thousands of dollars, estimated as of third quarter, 1979.

**The 25-year present value, as of the first year of benefit -- in this case 1986. It is obtained by multiplying the annual costs in 1980 times the values given in Table 3.

Table 15

Summary of Conversion Alternatives for Picatinny Arsenal*

Alternative	Capital Cost	Annual Operating Cost	Present Staff	Proposed Staff
Gasification Plant	$40.2 million (Table 8)	$12.0 million (Table 9)	50	75
Stoker Boilers	$57.2 million (Table 10)	$9.9 million (Table 11)	50	65
Fluid Bed Boilers	$51.8 million (Table 12)	$9.5 million (Table 13)	50	64

*This table summarizes the data given in the cited tables.
The costs are in 1985 dollars.

Table 16

West Point -- Steam and Fuel Requirements

1. Steam

Annual	620,000,000 lb/year (179 800 MW)
Peak	185,000 lb/hr (54 MW)
Average	71,000 lb/hr (21 MW)

2. Fuel*

	Oil	Coal
Annual	5,000,000 gal/yr (18 900 m^3/yr)	30,300 tons/yr (27 500 MT/yr)
Peak	1655 gal/hr (6.26 m^3/hr)	10.0 tons/hr (9.1 MT/hr)
Average	570 gal/hr (2.2 m^3/hr)	3.5 tons/hr (3.2 MT/hr)

*Based on fuel oil at 145,000 Btu/gal (404 kJ/m^3) and coal at 12,000 Btu/lb (28 MJ/kg).

Table 17

West Point -- Summary of Capital Costs for Fluid Bed Combustion Boilers*

Line Item	Amount
1. Coal delivery and handling	
Track work	47
Railcar unloading building	811
Coal preparation building	162
Conveyor to storage	156
Coal storage silos	1365
Silos hoppers	448
Conveyor to plant	156
2. Boiler plant	
3 Boilers @ 120,000 lb/hr (35 MW) (Includes in-plant coal handling)	23,393
3. Pollution control	
Baghouses	3197
Limestone storage	1622
Ash storage	1123
4. Yard work	
Electric	858
Utilities other than electric	286
5. Pipeline	3690
Subtotal	37,314
Contingency at 10 percent	3731
Total capital cost	41,045
SIOH at 5.5 percent	2257
Grand total, 1979 dollars =	43,302
Grand total, 1985 dollars =	61,400

*In thousands of dollars; costs estimated as of third quarter, 1979.

Table 18

West Point -- Summary of Operating Costs for Fluid Bed Combustion Boilers*

Item		Total	25-yr PV**
1.	Labor	900	12,550
2.	Repair materials	971	13,540
3.	Disposals	225	3140
4.	Electric	514	21,820
5.	Coal	1,500	43,200
	Grand total, 1979 dollars =	4,110	
	Grand total, 1985 dollars =	7,240	94,250

*In thousands of dollars; estimated as of third quarter, 1979.

**The 25-year present value, as of the first year of benefit -- in this case 1986. It is obtained by multiplying the annual costs in 1980 dollars times the values given in Table 3.

Table 19

West Point -- Summary of Capital Costs for Gasification Plant and Retrofit of Existing Boilers*

Line Item	Amount
1. Coal delivery and handling	
Track work	46
Railcar unloading building	794
Coal preparation building	159
Conveyor to storage	153
Coal storage silos	1782
Silo hoppers	586
Conveyor to plant	191
2. Boiler plant	
Gasifiers (5)	17,490
Pumping station	4201
Boiler conversion	764
3. Pollution control	
Ash storage	95
4. Yard work	
Electric	1349
Utilities other than electric	280
5. Pipeline	1470
Subtotal	29,360
Contingency at 10 percent	4404
Total capital cost	33,764
SIOH at 5.5 percent	1857

Grand total, 1979 dollars = 35,621
Grand total, 1985 dollars = 50,520

*In thousands of dollars; costs estimated as of third quarter, 1979.

Table 20

West Point -- Summary of Operating Costs for Gasification Plant and Retrofit of Existing Boilers*

Item	Total	25-yr PV**
1. Labor	1100	15,330
2. Materials	675	9410
3. Disposals	150	2100
4. Electric	960	40,760
5. Coal	2143	61,700
Grand total, 1979 dollars =	5028	
Grand total, 1985 dollars =	9281	129,300

*In thousands of dollars; estimated as of third quarter, 1979.
**The 25-year present value, as of the first year of benefit -- in this case 1986. It is obtained by multiplying the annual costs in 1980 dollars times the values given in Table 3.

Table 21

Summary of Conversion Alternatives for West Point

Alternative	Capital Cost*	Annual Cost*	Present Staff	Proposed Staff
Present oil operation	--	$10.9 million	22	Not applicable (NA)
Fluid bed	$61.4 million	$7.2 million	NA	36
Gasification plant	$50.5 million	$9.3 million	NA	44

*Costs are in 1985 dollars.

Table 22

Summary of Costs, Benefits, and Staff Requirements for Various Alternatives

Case-Location	Capital Investment: 1985 Dollars, in Millions	Annual Cost: 1985 Dollars, in Millions	Barrels of Oil Saved per Year, Thousands	Energy-to-Cost Ratio (E/C)	Staff Requirements
Case I: Redstone Arsenal					
Present practice	0	13.0	-	-	10
Rehabilitate/reconvert	19.0	3.4	152	62	28
New central plant	34.0	4.1	152	35	22
Case II: Picatinny Arsenal					
Present practice	0	19.9	-	-	50
Gasification plant	40.2	12.0	215	44	75
Fluid bed boilers	51.8	9.5	215	34	64
Stoker boilers	57.2	9.9	215	31	65
Case III: West Point					
Present practice	0	10.9	-	-	22
Gasification plant	50.5	9.3	120	20	52
Fluid bed boilers	61.4	7.2	120	16	36

Table 23

Summary -- Economics of Various Alternatives*

Case-Location	A Capital: Investment 1985 Dollars, in Millions	PV Life-Cycle Cost: 1985 Dollars, Millions	B Present-Value Savings 1985 Dollars, in Millions	Savings-to-Investment Ratio (SIR) (B/A)	Years to Payback (Straight Line)
Case I: Redstone Arsenal					
Present practice	0	260	-	-	-
Rehabilitate/reconvert	19.0	78.0	201	10.6	2.0
New central plant	34.0	90.9	204	6.0	3.8
Case II: Picatinny Arsenal					
Present practice	0	380	-	-	-
Gasification plant	40.2	198	222	5.5	5.1
Fluid bed boilers	51.8	167	264	5.1	5.0
Stoker boilers	57.2	169	268	4.7	5.7
Case III: West Point					
Present practice	0	210	-	-	-
Gasification plant	50.5	180	81	1.6	31.2
Fluid bed boilers	61.4	156	116	1.9	16.8

*The PV life-cycle cost of the present practice does not include capital investment, since it is a sunk cost, nor does it include maintenance and utilities, other than fuel, as do the proposed alternatives. Thus, the PV savings, SIR, and payback are all conservative.

Table 24

Limiting Parameters, Coal Conversions at Army Installations

Parameters	Constraint
Plant site	o Sufficient area must be available close to steam lines and access roads (rails).
Air pollution control requirements	o Applicable authorities must be willing to permit plant to operate.
Residue disposal	o Appropriate landfill must be available for disposal of system wastes.

Table 25

Life-Cycle Costs

	LCC Dollars, in Millions
Redstone	
Present practice (burn fuel oil)	260
Rehabilitated/reconverted to burn coal	78
New coal fired central plant	91
Picatinny	
Present practice (burn fuel oil)	380
Coal gasification plant	198
Fluid bed boilers (coal fired)	167
Stoker boilers (coal fired)	169
West Point	
Present practice (burn fuel oil)	210
Coal gasification plant	180
Fluid bed boilers (coal fired)	156

APPENDIX A

TECHNICAL-ECONOMIC EVALUATION OF COAL CONVERSION

AT REDSTONE ARSENAL, AL

PREPARED UNDER

Purchase Order DACA 88-79-M-0255

by

SCS Engineers, Inc.

CONTENTS

TABLES

FIGURES

TECHNICAL-ECONOMIC EVALUATION
OF COAL CONVERSION AT REDSTONE
ARSENAL, ALABAMA

1 INTRODUCTION

Background

Redstone Arsenal is a diversified Army installation located in north-central Alabama near the city of Huntsville. Both personnel and industrial activities take place; neither is predominant. Installation energy use averaged approximately 0.23×10^9 Btu/hr in 1979. Energy use at Redstone is seasonal, as evidenced by Figure 1,[*] indicating that space heating accounts for a large percentage of steam generation.

Two boiler plants, each constructed during World War II, supply the majority of the steam load at Redstone. Originally coal-fueled, both facilities were converted to fire oil in 1972. Accordingly, the boiler plants are now operated at only partial load.

Due to the advanced age of the steam production plants (both are nearly 40 years old), new facilities will soon be required at Redstone, regardless of coal conversion plans. At least one feasibility study addressing future energy options has been completed, and outlines a number of alternatives for new coal-fired steam capacity, some including electrical energy production.[1]

Figure 2 illustrates the relationship between the two principal steam plants (referred to as 4725 and 3624) and the two principal energy-consuming areas at Redstone Arsenal. Also shown is the proposed site of a new centrally located steam production facility.

Steam plant 4725 is equipped with four 100,000-pph oil-fired boilers, which were originally designed to be operated on coal. Plant 3624 is equipped with four 60,000-pph boilers of similar background. Plant 4725 boilers were originally fired with pulverized coal, while plant 3624 boilers utilized underfired vibrating grate stokers. Plant 3624 was rebuilt in 1960, including installation of new boiler tubes. Plant 4725 has never been rebuilt, and is presently nearing the end of its operational life.

---

[1] Black & Veatch Consulting Engineers, *Basewide Energy Systems Plan - Total Energy and Selective Energy*, Draft Final Report DACA01-77-C-0094, Vol. 1 (Mobile District Corps of Engineers, October 1979), pp 1-51.

[*] The Figure numbers in this appendix refer only to the figures in this appendix and should not be confused with those in the main text.

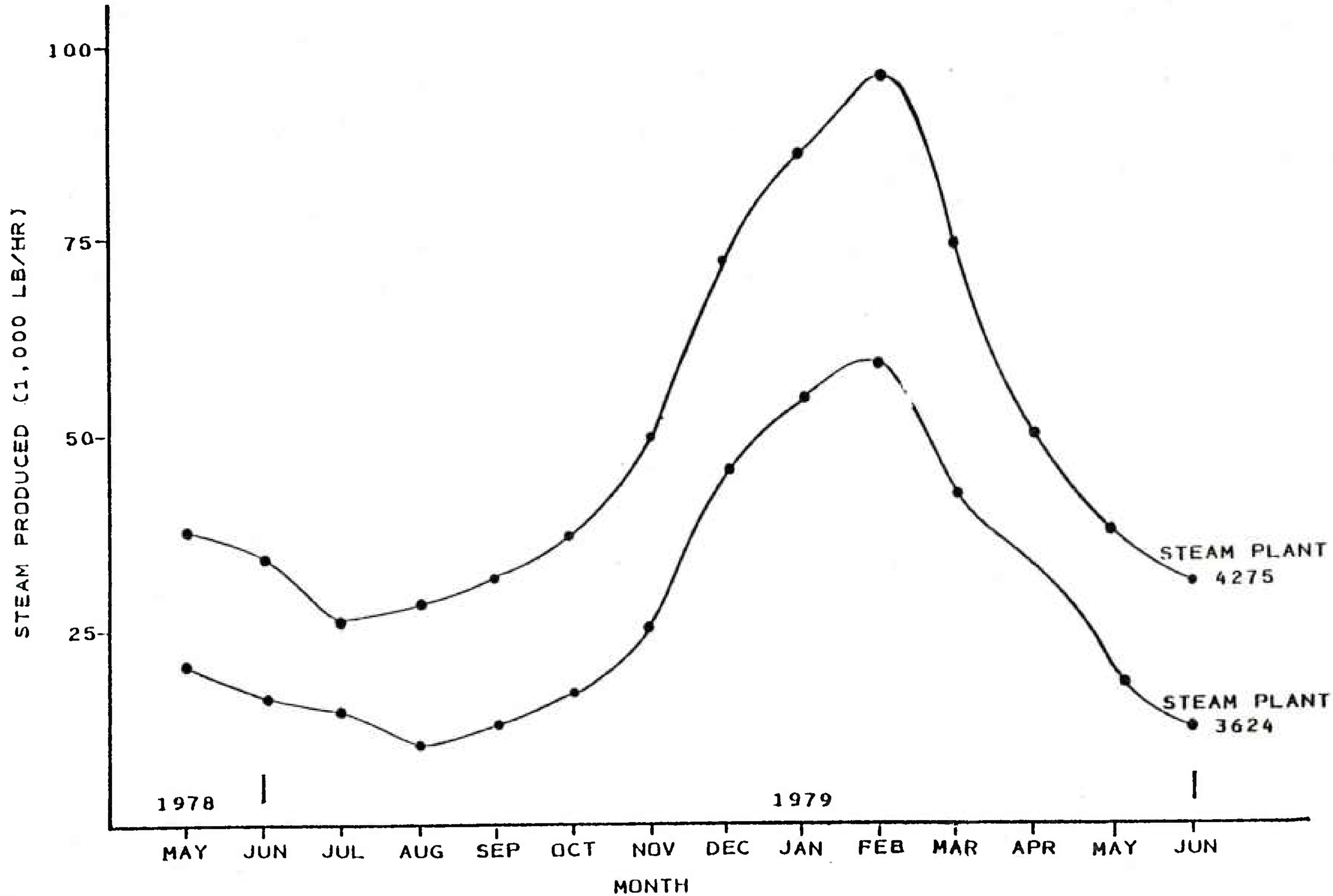


Figure 1. Seasonal average steam demand, Redstone Arsenal.

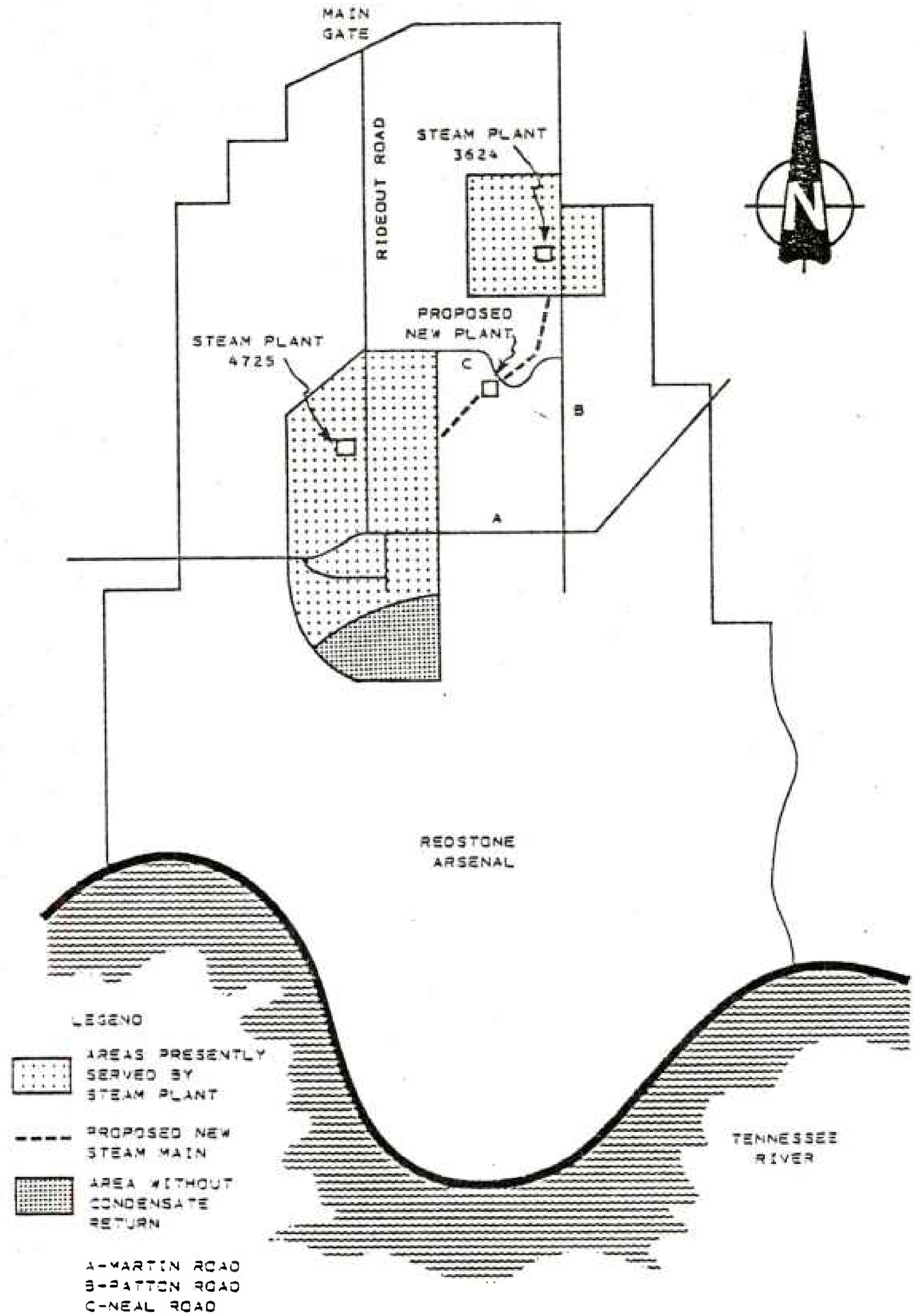


Figure 2. Redstone Arsenal, steam generation and use.

Twenty-four other gas/oil-fired, steam-producing boilers are scattered throughout the installation at 10 different locations (excluding residential heaters). The largest of these boilers is rated at 30,000-pph steam. However, most are small units averaging 6,000 pph. Together, these boilers provide 16% (160,000 pph) of the total nameplate capacity at Redstone.

The steam distribution system at Redstone is in need of major upgrading, whether or not coal conversion is implemented. The southerly portion of the area served by steam plant 4725 presently lacks condensate return. Consequently, large volumes of make-up water are required, and result in inefficient operation (see Figure 2). Additionally, due to inadequate insulation and line malfunction, steam loss amounts to 10% throughout the entire distribution system.

The immediate need to improve energy production facilities at Redstone Arsenal, and the Army's increased interest in reducing dependence on imported oil, are two primary reasons for planning fuel conversion in the near future. The availability of coal in the northern Alabama area further pinpoints Redstone Arsenal as a likely location for installation of coal-fired facilities. This report describes several alternative strategies for fuel conversion at Redstone, and presents the technical, economic, and environmental criteria for selection of the most viable option.

Objective

The primary objective of this study was to evaluate the applicability of demonstrated technologies for fuel conversion at Redstone Arsenal. Technical, economic, and environmental considerations were included in the analysis. A secondary objective was to perform a test application of CERL Interim Report E-148, Project Development Guidelines for Converting Army Installations to Coal Use. This reference was used extensively for guidance throughout the course of the study.

Approach

Three methods were used to develop project results: literature search, guideline manuals (specifically CERL Reports E-130 and E-148), and on-site investigation.

An abundance of references were found to detail the development of new, industrial-scale coal-fired steam plants, including a recent feasibility study specific to Redstone Arsenal. A great deal less information related to the conversion or reconversion of oil/gas-fired boilers to coal. Apparently, the motivation to undertake coal conversion is so recent that few applicable publications have yet been circulated.

CERL reports E-130 and E-148 were used extensively because (a) both documents are directly applicable to project objectives; and (b) because test use of these reports is specifically called for in the scope of work. The project organization and the investigation procedure were based on those references.

On-site investigation was conducted to inspect existing equipment and facilities, as well as to interview Redstone operating and supervisory personnel. Additionally, a substantial amount of information pertaining to energy production and use at Redstone was reviewed and clarified during the site visits.

Scope

This report evaluates the technical and economic feasibility of converting the heating and power system at Redstone Arsenal (excluding residential size furnaces) to coal as a primary fuel. Both current and advanced coal systems, including direct combustion, low- and high-Btu coal-derived gas, and coal-derived liquid fuel, were considered.

A section of the report addresses specific findings and recommendations with respect to validation and/or revisions of concept and cost data presented in CERL Interim Report E-148, Project Development Guidelines for Converting Army Installations to Coal Use.

2 DEVELOPMENT AND EVALUATION OF CONVERSION CONCEPT ALTERNATIVES

The coal conversion concept alternatives applicable at Redstone Arsenal can be broadly categorized as follows:

1. New coal-fired central steam plant.
2. New coal-fired satellite plants.
3. Rehabilitation/reconversion of existing plants.
4. New coal liquefaction/gasification plant.

A number of variations are possible under each category.

Application of specific operating constraints at Redstone Arsenal to implementation parameters associated with each concept alternative determined the two most feasible conversion strategies. Table 1 lists the major advantages and disadvantages associated with each concept alternative. Table 2 summarizes the principal factors at Redstone Arsenal which affect concept selection. The following discussion briefly outlines the criteria and rationale for selecting or rejecting each alternative.

New Coal-Fired Central Steam Plant

This alternative has previously received considerable interest at Redstone Arsenal.[2] A central location is available nearly equidistant from the existing steam distribution grids of plants 4725 and 3624 (see Figure 2). Approximately 1 mile of new steam main would be required for the new facility to tie into each grid. The proposed location is presently undeveloped, and would require extensive site improvements.

As currently envisioned, the new central facility would utilize two pulverized coal-fired boilers with residual fuel oil-firing capability.[3] Additionally, one residual fuel oil-firing boiler would be included. All three boilers would be rated at 192,000 pph. As sized, only two of the three boilers would be required at any one time, and only one boiler would be required over 60% of the time.

Suspension-fired pulverized coal boilers with back condensing turbines were specified as the optimum system design in the above-mentioned

---

[2] Black & Veatch Consulting Engineers, *Basewide Energy Systems Plan - Total Energy and Selective Energy*, Draft Final Report DACA01-77-C-0094 (Mobile District Corps of Engineers, October 1979).

[3] Black & Veatch Consulting Engineers.

Table 1

Redstone Arsenal Coal Conversion Alternatives

Alternative	Advantages	Disadvantages
New Coal-Fired Central Steam Plant	• Developed Technology • Credible Cost Forecast • Minimize New Distribution System Development • Potential for Use of Alternate Fuels	• Large First Cost • No Utilization of Existing Energy Equipment
Rehabilitation and Reconversion of Existing Steam Plants	• Maximum Utilization of Existing Equipment • Lower First Cost • No New Site Required	• Increased Recurring Costs • Difficult to Accurately Predict First Costs
New Coal Liquifaction/ Gasification Plant	• Utilization of Existing Boiler Equipment • Greater Environmental Acceptance	• Large First Cost • Undeveloped Technology • Need to Rehabilitate Existing Boiler Equipment • Low Acceptance by Redstone Personnel
New Coal-Fired Satellite Plants	• Additional Redundancy • No New Distribution System Development Required • Lower Recurring Costs vs. Rehabilitation	• Lose Economies of Scale • Large First Costs • Greater Recurring Costs Than Central Plant

Table 2

Concept Alternative Selection Criteria

Alternative	Principal Criteria
New Coal-Fired Central Steam Plant	• Extensive feasibility study of this option already completed. • Undeveloped site available equidistant between existing plants. • Economies of scale favor larger facility. • Existing plants remain available as backup.
Rehabilitation and Reconversion of Existing Steam Plants	• Plants were originally designed for coal use, and most auxiliary equipment is still in place and functional. • No new development of distribution system required. • Able to utilize maximum of existing development. • Lowest first cost option. • Highest direct combustion recurring cost option. • Escape strict air pollutant emission regulations.
Coal Liquefaction/Gasification Plant	• Low acceptance of technology by Redstone personnel. • Besides development of coal conversion plant, existing boilers would require extensive rehabilitation. • Highest first cost option. • Highest recurring costs also.
New Coal-Fired Satellite Plants	• Lose economies of scale vs. new central plant. • Provides little additional flexibility over central plant. • Higher first costs than rehabilitation of existing system. • Lower recurring costs than rehabilitation.

report. Although spreader stoker systems compromise combustion efficiency relative to suspension-fired equipment, the operational and environmental benefits can offset combustion losses in the specified size range. Consequently, for the purposes of this analysis, two spreader stoker-fired boilers, rated at 175,000-pph steam each, will instead be considered.

Coal would be delivered to this facility by truck, and residues would be hauled away in a similar fashion. This mode of transport will be utilized in all four concept alternatives.

Due to its size and regulatory status (new source), the proposed central plant would be subject to strict federal air pollution control regulations.[4] However, if the rated size of each boiler were reduced by only 7%, federal regulations would no longer apply. State air pollutant emission standards for industrial size boilers are considerably less restrictive.[5] By avoiding federal New Source Performance Standards (NSPS), no sulfur oxides control and minimal particulate emissions control would be required.

At reduced system capacity, central steam generation would result in maximum control of air pollutant emissions for minimum unit cost. Additionally, the proposed new plant site is well removed from potential receptors, whereas the existing steam plants are surrounded by offices and other inhabited buildings.

No service interruption would occur during implementation of this alternative due to the independence of the existing and replacement systems. Start-up and shakedown operations would similarly be unaffected by day-to-day operational demands.

Implementation of this alternative would also result in an overall increase in staffing from present levels. Coal-fired steam plants are inherently more labor-intensive than oil- or gas-fueled facilities. However, a central facility would require fewer operation and maintenance personnel than any of the other four coal conversion alternatives.

Installation of a new, centrally located coal-fired steam plant was selected for further consideration in Phase II. Inherent ease of implementation, high energy efficiency, environmental protection, cost

---

4 D. G. Streets and T. A. Speciner, *Issues Relating to New Source Performance Standards for Industrial Steam Generators*, Technical Memo ANL/EES-TM-54 (Argonne National Laboratory, June 1979).

5 *Rules and Regulations* (Alabama Air Pollution Control Commission, September 1976).

effectiveness, and redundancy were the major reasons for selection of this alternative.

New Coal-Fired Satellite Plants

This alternative is essentially a replacement of existing facilities. Little, if any, in-place equipment could be incorporated into the replacement systems. Two new sites would need to be located, developed, and tied into the existing steam distribution grid.

Three 100,000-pph traveling grate stoker-type boilers would replace the four existing boilers at steam plant 4725, and two 100,000-pph traveling grate stoker-type boilers would replace the four boilers at plant 3624. All boilers would be capable of firing residual oil as a backup, and would utilize the existing oil tank storage complex at each plant.

Two boilers, each at steam plants 3624 and 4725, could be maintained as backup for the new systems. These units would continue to fire oil as their primary fuel. The two steam distribution grids would operate independently as they do now.

Use of identical stoker-type boilers at both locations would simplify operation and maintenance activities. More staff will be required for two satellite plants than for one central plant, but less personnel than for either the rehabilitation/reconversion or the gasification/liquefaction option. Similarly, overall energy conversion efficiency will be less for two smaller plants than for one central plant, but greater than for system rehabilitation and pyrolysis.

Under Alabama law, allowable particulate emissions from coal-fired equipment are inversely proportional to size, i.e., smaller boilers are allowed greater emissions.[6] A system consisting of many small boilers is therefore permitted greater total emissions than a system consisting of a few large boilers. Total pollution control expense is greater for the smaller boiler system, however, due to economies of scale inherent in particulate and SO_x abatement. Consequently, relative to a central system, a series of satellite plants would result in both increased air emissions and increased pollution abatement expense.

This alternative offers no major advantage over any of the other conversion options. Overall, the two satellite plants are much more expensive than either a new central plant or a rehabilitated facility. The capital cost of two satellite boiler plants (excluding facilities)

---

6 *Rules and Regulations* (Alabama Air Pollution Control Commission, September 1976).

is 20% higher than the cost of a control plant of equal capacity.[7] Recurring costs will similarly be higher for two satellite plants than for one central plant. On the other hand, recurring costs for two new satellite plants would be considerably less than for the existing facilities (even after extensive rehabilitation), due to their age and condition.

Installation of two new satellite steam plants at Redstone was not selected as a coal conversion alternative for consideration in Phase II, due to reduced efficiency, higher costs and air pollutant emissions, and possible implementation problems.

New Coal Liquefaction/Gasification Plant

As an alternative to direct coal combustion, coal liquefaction/gasification could be utilized to provide suitable fuels for existing equipment. As applied to Redstone Arsenal, a liquefaction/gasification plant would be located at a convenient, central site from which pipe lines would transport the coal-derived oil/gas to steam plants 3624 and 4725. Other smaller steam plants at Redstone would probably be served by tanker truck.

As noted earlier, steam plants 4725 and 3624 are the two largest energy production facilities at Redstone Arsenal. Approximately 160,000 pph of gas/oil steam capacity, scattered throughout 24 other installations, could potentially be coal gas/oil-fired. However, this represents only 16% of the total Redstone steam capacity.

A number of possible coal liquefaction/gasification technologies are available, all based upon pyrolysis of coal under elevated temperature and pressure conditions. Probably the most commercially advanced coal gasification process is the Koppers-Totzek system, shown schematically in Figure 3.[8] Ducting, burner, and control modifications would be required to fire the 300 Btu/ft^3 product gas in existing Redstone boilers. A downgrading of approximately 40% from oil firing, or 15% from coal firing, would be required. Due to their age and condition, rehabilitation of the existing boilers at steam plants 3624 and 4725 would also be required within the next 5 years if coal-derived gas or oil were used.

---

[7] B. D. Coffin, "Estimate the Cost of Your Next Coal-Fired Industrial Boiler Plant," *Power*, Vol. 121, No. 10 (October 1977), pp 28-29.

[8] E. M. Honig, Jr., and S. A. Hathaway, *Application of Modern Coal Technologies to Military Facilities, Volume I: Summary of Findings*, Interim Report E-130 (CERL, May 1978).

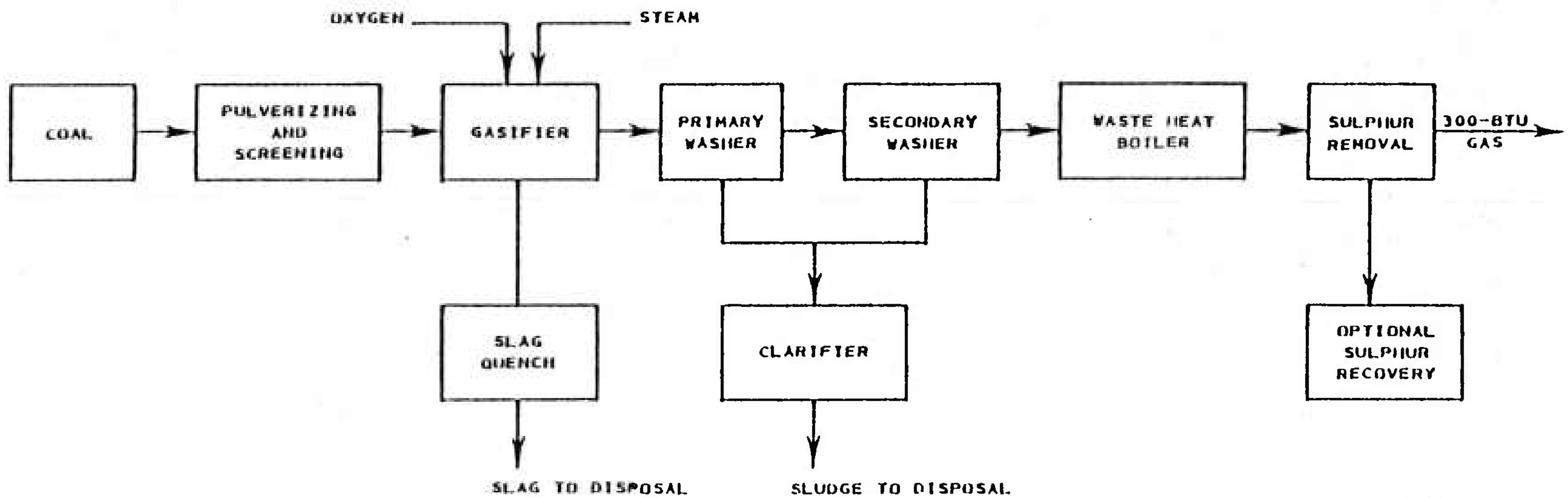


Figure 3. Koppers-Totzek coal gasification process.

Greater environmental control can be exercised through coal gasification/liquefaction than through direct combustion. Particulate emissions from the combustion of coal gas are inherently low, as are sulfur oxides emissions due to the removal of most fuel-bound sulfur in the pyrolysis process. Additionally, nitrogen oxides emissions are reduced due to the lowering of peak combustion temperatures. Disposal of pyrolysis residue, or char, can be a problem, particularly if this material is classified as a hazardous waste. At this time, however, it can be disposed of in sanitary landfills.

Coal liquefaction/gasification is the least attractive coal conversion alternative at Redstone Arsenal. The primary advantage to coal liquefaction/gasification is the potential for utilization of the product in existing combustion facilities. At Redstone, the existing boiler facilities have reached the end of their useful life, and would require a major investment in order to remain operational for the life of the pyrolysis plant.

Conversion of coal to liquid or gas is still an experimental technology. Consequently, it is difficult to accurately predict total capital and operating costs. Operation of a pyrolysis plant at Redstone would require 30 to 50 additional personnel, many of whom need to be experienced in chemical plant operation. Additionally, the overall fuel-energy conversion rate for liquefaction/gasification is low compared to direct combustion technology.

Interviews with Redstone personnel indicate a lack of enthusiasm for advanced technology systems. This is due in part to (1) the difficulties involved with construction and start-up of unproven systems; and (2) the apparent high cost of building both a suitable liquefaction/gasification plant, and of rehabilitating boiler plants 4725 and 3624.

Based on the economic, technological, and operational disincentives described above, coal liquefaction/gasification was excluded as a final concept alternative for Phase II.

Rehabilitation and Reconversion of Existing Steam Plants

Of the four strategies under consideration, rehabilitation and reconversion of existing facilities would be the simplest, most straightforward, and least costly alternative over the short term. Steam plants 3624 and 4725 were both originally designed and constructed to burn coal. Converting both facilities back to coal would therefore be relatively simple. Without rehabilitation, however, the reconversion to coal would be only a short-term solution.

It is difficult to assess precisely how much rehabilitation would be required in order to prolong the economic life of each plant for another 20 years. For the purposes of this analysis, the worst condition was assumed: all boiler internals would require replacement, and

most auxiliary equipment would require a complete overhaul. Additionally, at plant 4725, a new coal storage area would be needed.

As originally designed, the boilers at steam plant 3624 were equipped with underfired vibrating grates. Plant 4725, on the other hand, was suspension-fired with pulverized coal. In order to standardize maintenance and operation activities, as well as to facilitate rehabilitation design and construction, traveling grate spreader stokers are recommended for use in both plants. Besides the simplicity of operation, this equipment also minimizes air pollutant emissions.

Originally sized for coal, both boiler plants exceed the necessary steam generating capacity at Redstone Arsenal. Figures 4 and 5 show the projected future relationship between boiler capacity and energy demand after coal conversion for both plants 3624 and 4725. As indicated by these graphs, at peak demand, the steam load can be supplied by two of the four boilers at each plant.

Because it does not result in reclassification as a new source, rehabilitation is subject to much less stringent air pollution control requirements than the new central plant, as currently envisioned. Implementation of this alternative will be considerably more complex than any of the new facility options. Construction activities will have to be coordinated with normal operations requiring a staggered schedule, i.e., a maximum of two boilers can be taken off line at each plant at any one time. Consequently, the construction schedule will be drawn out longer than normal for conversion of this type.

Utility and steam line work will be similarly complicated. In addition, start-up and shakedown activities will be more involved, and consequently more expensive. Assuming only two boilers at each plant were rehabilitated at one time, two identical start-up and shakedown phases would be required.

Staff personnel are already familiar with the system layout at plants 4725 and 3624, a factor which will considerably facilitate shakedown. Additional staff required to operate the coal-fired system will be limited to five at each plant: two coal pile superintendents, two boiler operators, and one mechanic. Sufficient storage is available in the overhead coal bunkers to dispense with coal handling activities during the evening shifts.

The capacity of the boilers at plants 4725 and 3624 is well below the limit set for federal air pollution guidelines. Alabama particulate and sulfur oxides limitations are less restrictive than federal regulations. Considering the projected coal usage at Redstone Arsenal, no sulfur oxides control and minimal particulate control equipment would be needed.

Rehabilitation and reconversion of existing steam boiler plants at Redstone Arsenal was selected as the second coal conversion concept

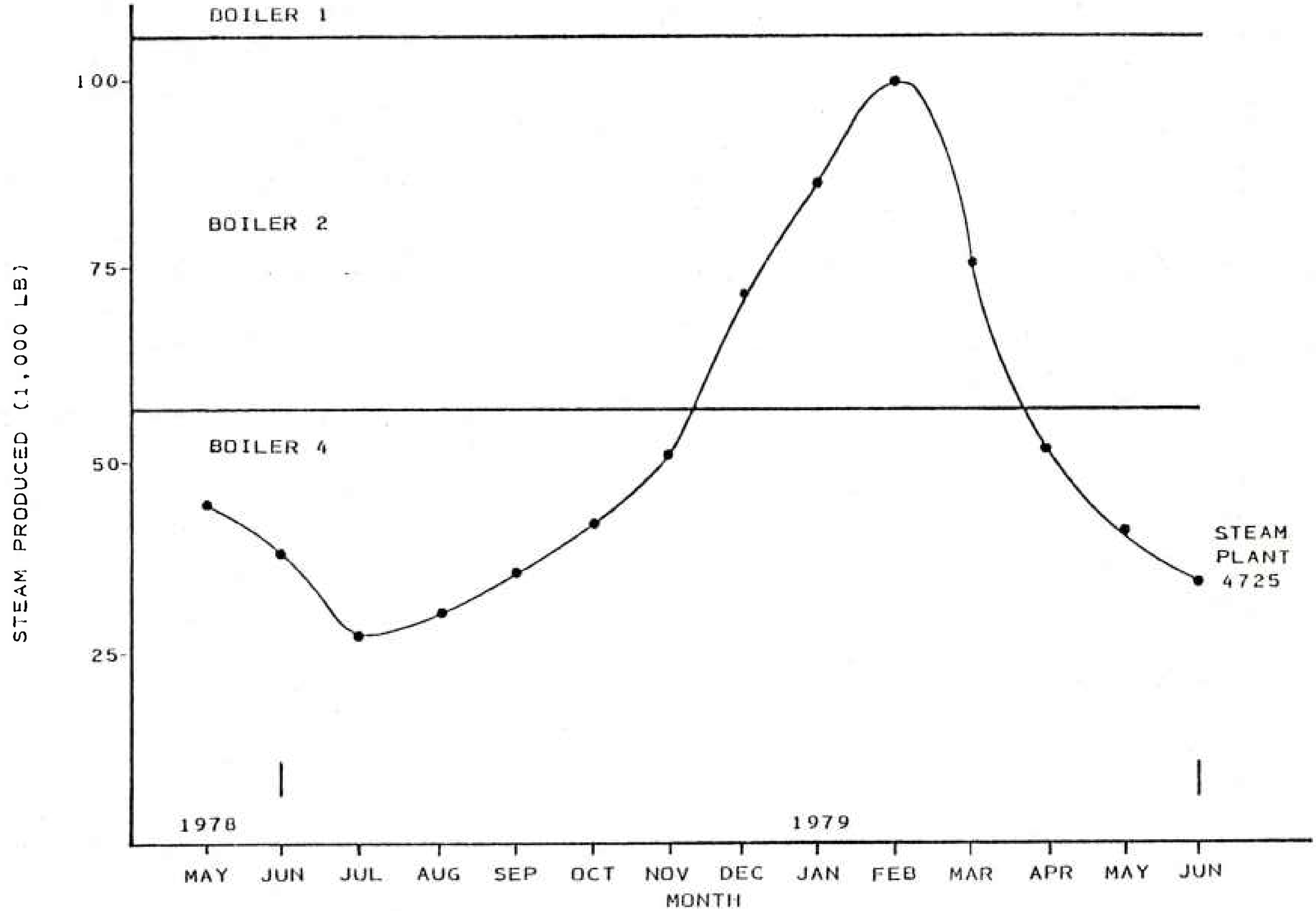


Figure 4. Steam demand versus steam capacity - Plant 4725.

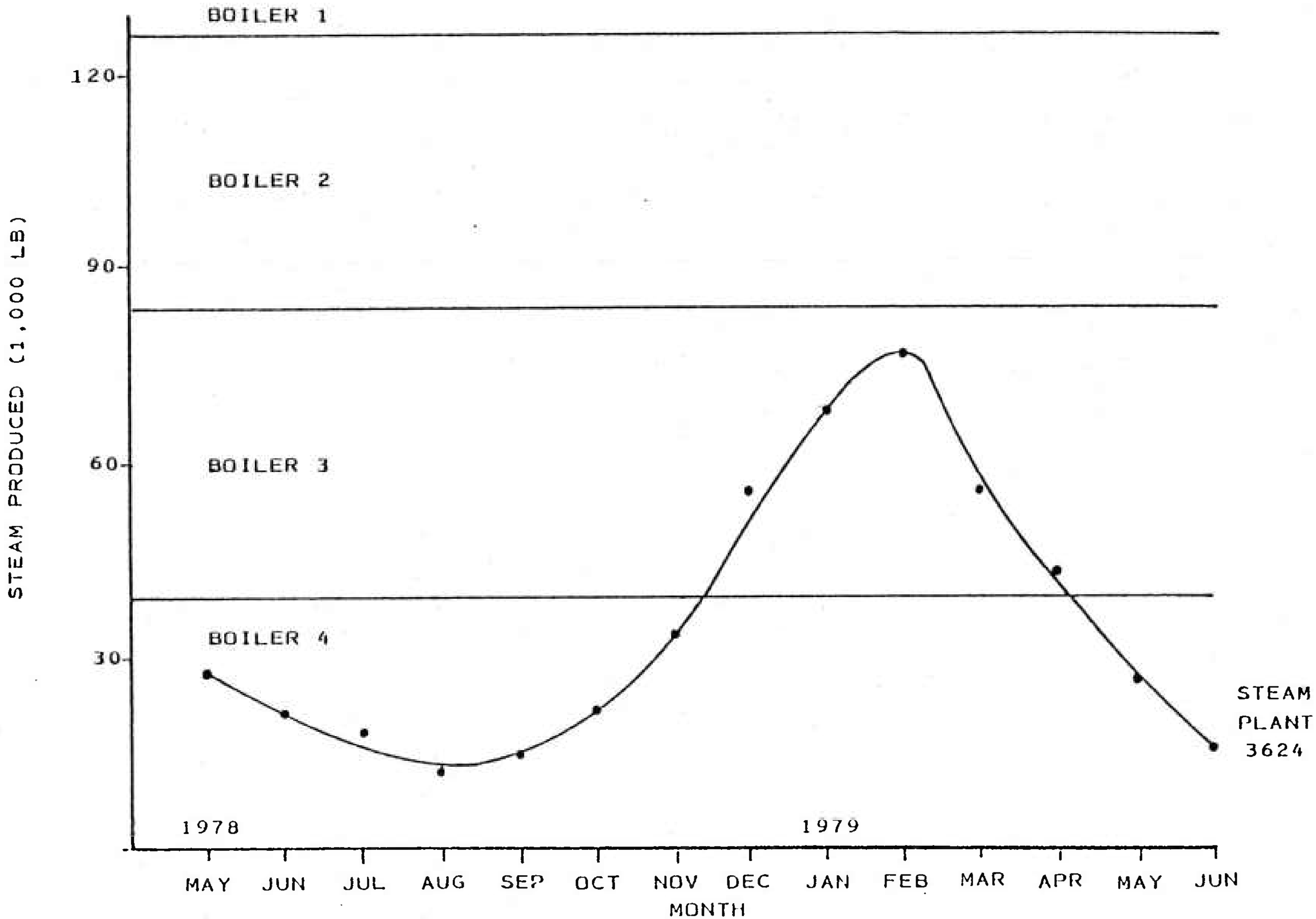


Figure 5. Steam demand versus steam capacity - Plant 3624.

alternative for consideration in Phase II. The low capital cost relative to the other three alternatives was the primary reason for selection.

Summary

A new, centrally located coal-fired steam plant was selected as a final concept alternative both because it offers the highest combustion efficiency, greatest ease of implementation, and greatest environmental protection; and because it provides for adequate redundancy. The use of two satellite plants was rejected because they were deemed inferior to one central plant on all of these points, and were considerably more expensive than the rehabilitation and reconversion of existing plants. Gasification/liquefaction was rejected due to the high cost and unproven technology.

3 REHABILITATION AND RECONVERSION OF EXISTING STEAM PLANTS

As outlined previously, a number of advantages are associated with the rehabilitation and reconversion of the existing power plants to coal. Probably the biggest disadvantage is the uncertain degree of conversion necessary. Based upon performance, past maintenance records, and on-site inspection, it appears that all boiler internals (including tubing, refractory, and grating) would require replacement. Additionally, some ducting and all controls would need rehabilitation. In this chapter, each facet of boiler reconversion is examined and the associated costs estimated.

Fuel Delivery

All of the four primary modes of coal delivery available (truck, rail, barge, and pipeline) are potentially applicable to Redstone Arsenal. A coal slurry pipeline, however, can be rejected immediately because no existing pipeline is available. Coal usage is too low to justify construction of a special line. Barge delivery is possible (along the Tennessee River) but impractical, because coal loading and unloading facilities are unavailable, and coal use is insufficient to justify their construction.

Previously, coal was delivered to Redstone via rail haul. After the conversion to oil, the rail lines into Redstone were removed. The rights of way and rail beds are still extant. As with pipeline and barge transport, however, the volume of coal delivered to Redstone is not sufficient to justify reinstallation of rail lines.

Coal delivery by truck has the twofold advantage of requiring minimal capital improvements, and providing a ready means for ash removal. The roadways to both power plants are capable of supporting maximum coal truck axle weights, so no road bed reinforcement is required. Truck delivery also provides greater flexibility in coal pile management. At maximum demand, an average of only three truck loads of coal per day would be delivered to each plant.

In order to keep track of the quantity of fuel in storage, as well as providing a record for payment, coal deliveries would be weighed upon receipt. The small number of daily truck deliveries would not require a full-time scale operator. The equipment operator (coal bulldozer) could serve in that capacity.

Fuel Storage

Coal would be at both plants in outdoor piles and indoor bunkers. At the larger of the two plants (4725), oil tanks now occupy the

property previously dedicated to coal storage. Figure 6, the view north from the roof of this facility, clearly shows the remains of the 7-year-old coal pile emerging from the toe of the dike surrounding the oil storage tanks. In order to provide sufficient room for future coal storage, the building visible to the right would be removed or relocated. Delivery would be from the primary road (Rideout Road) visible in the extreme upper right of the figure.

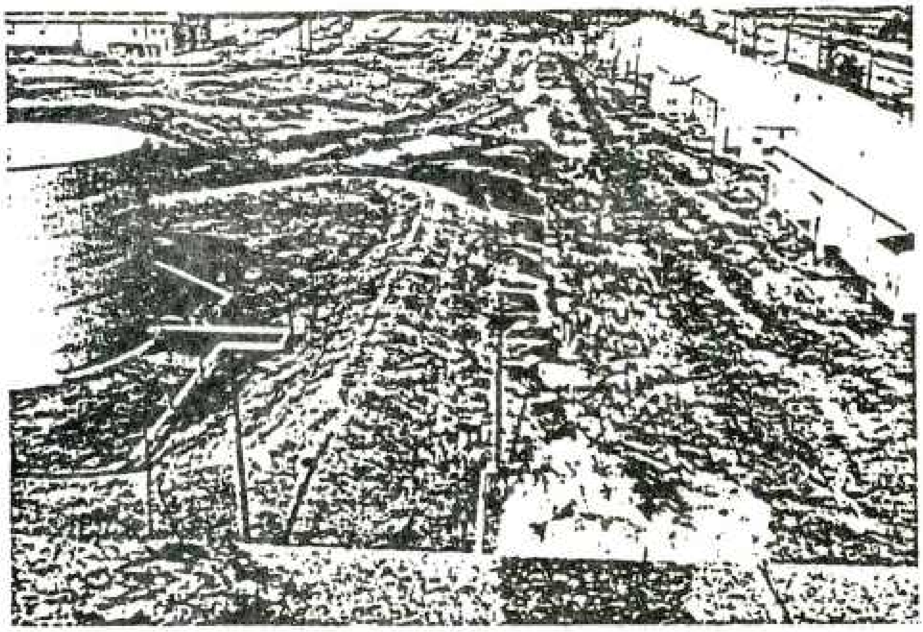


Figure 6. View North from Plant 4725.

At the smaller plant (3624), the property formerly dedicated to outdoor coal storage is still available. Some minor improvements in roadway access would probably be necessary to provide for efficient truck unloading.

Since the same area that was formerly used for coal storage is still available at plant 3624, and since the coal to be utilized is similar in heating value to coal previously burned, outdoor reserve storage area is assumed to be adequate. At plant 4725, the area required for outdoor reserve storage can be estimated as:

$$\frac{275{,}000\left(\frac{\text{lb}}{\text{Hr}}\right)24\left(\frac{\text{Hr}}{\text{day}}\right)(0.8)\ 90\ (\text{days})}{9.0\left(\frac{\text{lb steam}}{\text{lb coal}}\right)\ 45\ \left(\frac{\text{lb}}{\text{ft}^3}\right)\ 15\ (\text{ft})} = 78{,}222\ (\text{ft}^2)$$

which is based upon a 90-day storage capacity and a 15-ft (4.8-m) average pile height.[9] The area available for reserve storage is estimated at 78,000 ft^2 (7,267 m^2) if building 4723 is removed. Figure 7 depicts the boundaries of this parcel.

The only equipment needed at each site for coal pile management would be a bulldozer. The amount of coal movement required can be minimized through proper direction of truck deliveries.

Some site preparation will be required at both locations. Since a portion of the outdoor coal storage area to be used at plant 4275 previously served another function, the site preparation expense will be greatest there.

After handling (discussed in the next section), coal would be stored in overhead hoppers prior to feeding. Each boiler at both steam plants has one associated hopper capable of holding a two-day supply of coal at maximum load. No modifications are envisioned for the feed hoppers, although flow aids (i.e., shakers) may prove to be necessary.

Fuel Handling

Coal handling at both steam plants will involve conveyance from outdoor reserve storage to indoor feed bin storage, and size reduction for stoker firing. At plant 4725, most of the equipment for conveying and crushing has been dismantled and removed. At plant 3624, this equipment is still intact.

Plant 4725 formerly employed an outside crusher located in a concrete pit at the northeast corner of the plant building (southeast corner of the coal pile). This pit is shown in Figure 8. An opening in the side of the building, through which the transfer conveyer passed, has now been sealed. The elevator system within the building is still intact, but in a poor state of repair.

Rehabilitation of the coal handling and preparation system at plant 4725 would require reconditioning of the crusher/receiving pit, installation of a new coal crusher, reconnection of the internal coal elevation system to outside preparation equipment, and a complete overhaul of the internal distribution system.

---

[9] S. A. Hathaway, et al., *Project Development Guidelines for Converting Army Installations to Coal Use*, Interim Report E-148 (CERL, March 1979).

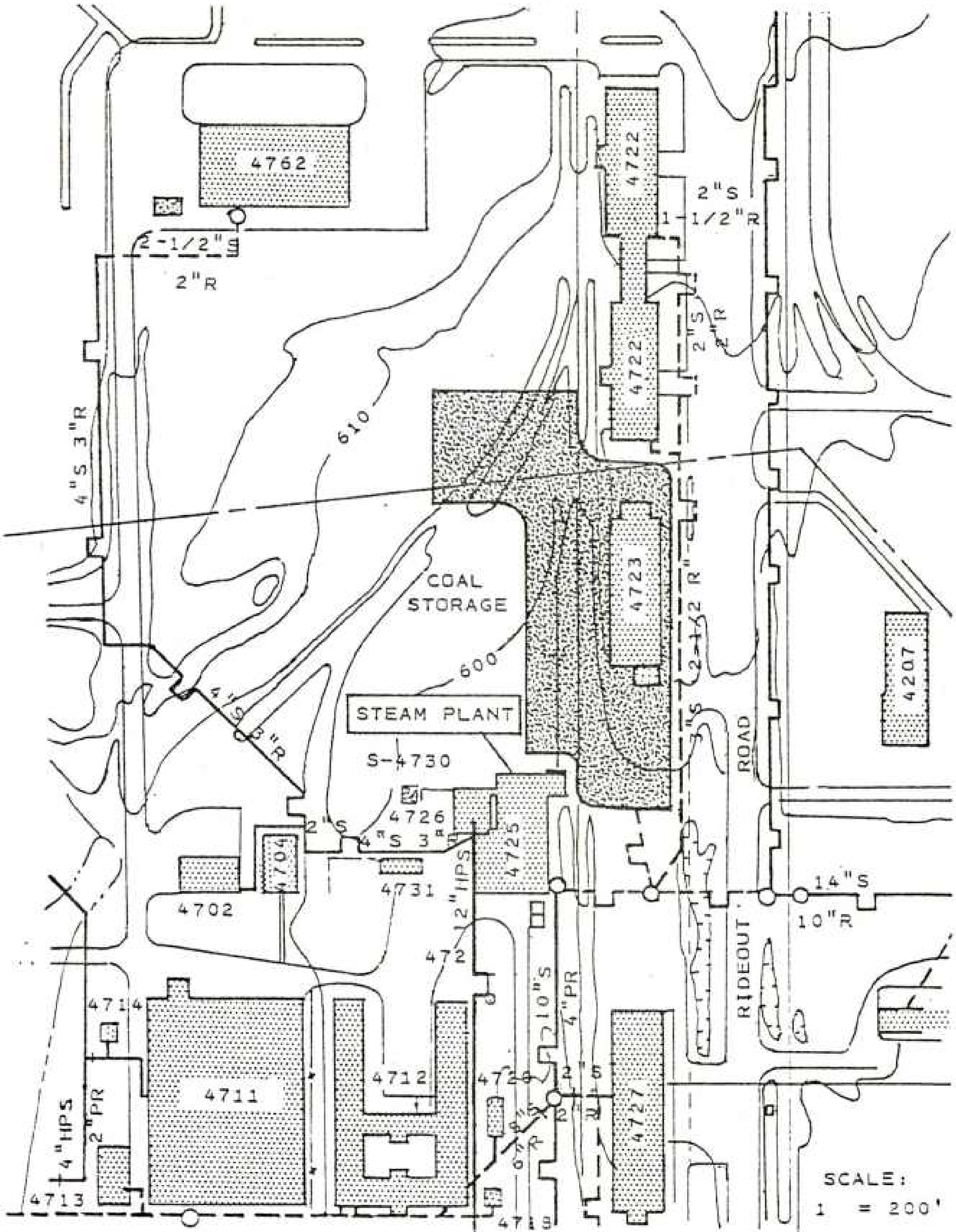


Figure 7. Coal storage area - Plant 4725.

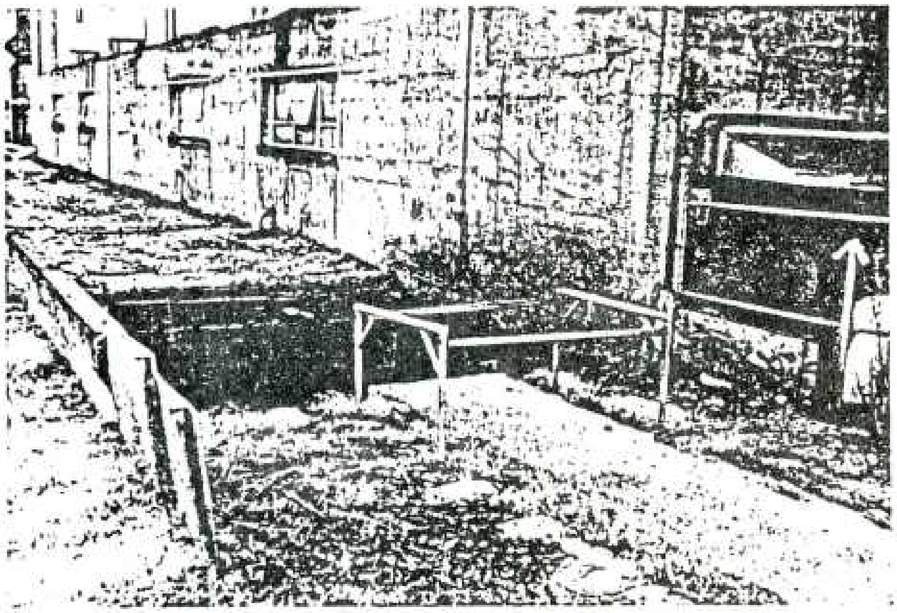


Figure 8. Coal Pulverizer Pit - Plant 4725.

The existing state of coal crushing and distributing equipment at steam plant 3624 is similar to that at 4725. The coal crushing and receiving system would require complete replacement. Coal elevation and distribution apparatus are in need of major overhaul, with the possible replacement of many key parts. It is possible that only the framework of each system can be salvaged.

Boiler Conversion

As described previously, all boilers in both steam plants 4725 and 3624 were originally sized and designed for coal. When converted to oil, the coal feed chutes were disconnected, the grate mechanism was removed, and oil burners were installed in each boiler. Also, induction fans were modified to supply additional combustion air as needed. Some ducting and dampers were remodeled or replaced to accommodate the greater gas flows.

Some, but not all, of the modifications made when each plant was converted to oil will have to be remodified with the conversion back to coal. The oil burners and attachments will be removed, and the coal feed chutes reattached. Due to age, the existing boiler internals will be entirely replaced. This will allow the installation of new traveling chain grates to replace the underfired vibrating grates at 3624, and the pulverized coal combustion equipment formerly employed at 4725.

New refractory and steam tubes will be installed in each boiler at both plants. Use of traveling grate stokers will result in minimal modification to the existing ash collection system. Additional advantages of traveling grate stokers are the reduction in maintenance costs because of identical systems at both plants, minimization of air pollutant emissions, and high combustion efficiency. Since none of the eight boilers in question was originally designed for traveling grate stokers, extensive modification will be required for grate mounting and drive. However, complete drive overhaul would be necessary in any case. Only minor modification will be required for the coal feed gates if traveling grates are used.

Though functional, boiler controls currently in use at both plants are of obsolete design, and do not provide the degree of air pollutant emission monitoring and control required. New grate controls would also be required. Consequently, a complete digital control system for both steam plants is recommended. At a minimum, controls will monitor:

1. Fuel flow to each boiler.
2. Air flow to each air port.
3. Grate speed.
4. Combustion temperature/pressure.
5. Steam temperature/pressure.
6. Steam flow.
7. Exhaust temperature.
8. Exhaust CO_2 and O_2 concentration.
9. Exhaust particulate concentration.

Control of these parameters allows the boiler operators to select the best combinations of boilers and load to minimize air pollutant emissions, and to maximize fuel combustion efficiency. Inclusion of a small computer system in the controls would improve operator accuracy and response time.

Selection of combustion air fans depends upon total system operation, including the air pollution control equipment. The existing fans are oversized for coal combustion. However, air pollution control pressure drops may require additional fan horsepower. In order to optimize system performance and flexibility, the combustion air fans should be overhauled and rated for boiler air flow only. Air pollution control exhaust flow requirements will be supplied by equipment that is specific to this application.

Residue handling capability is still in place at both steam plants. Figure 9 shows the elevated storage bunker at plant 4725. The ash conveyer from the plant can be seen in the center of the photo. The opening through the wall has been sealed and would require reopening. Figure 10 shows the elevated ash bunker at plant 3624, which is in a similar state of repair.

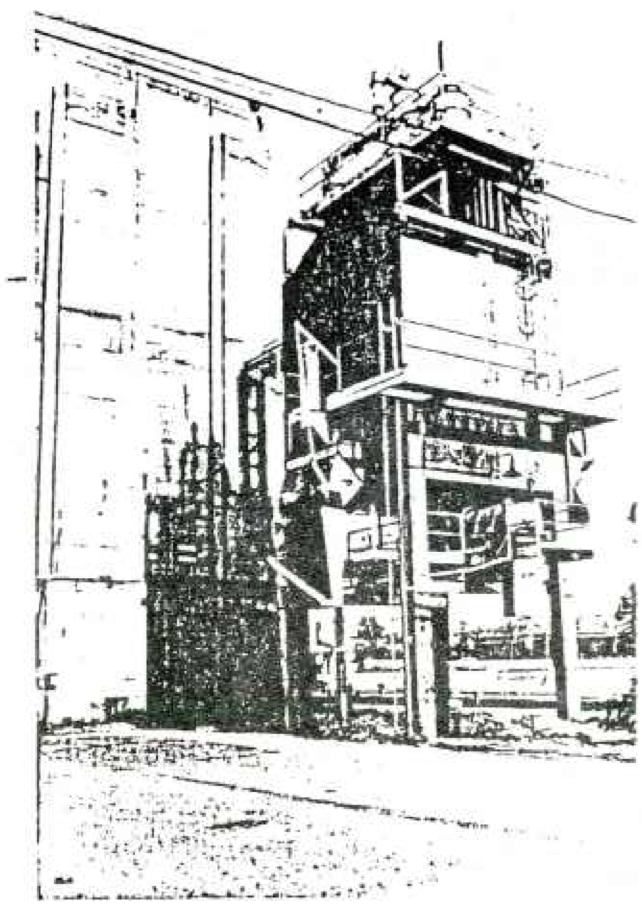


Figure 9. Elevated ash bunker - Plant 4725.

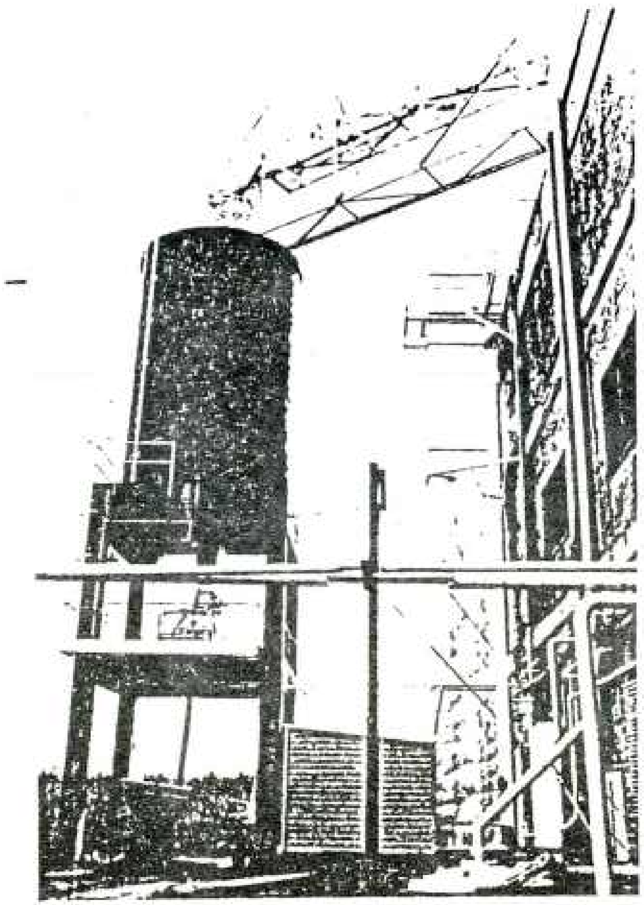


Figure 10. Elevated ash bunker - Plant 3624.

Rehabilitation of the ash handling systems at both plants would require renovation of the ash removal locks in the bottom of each boiler, overhaul of the ash conveyer and elevation systems, and renovation and repair, where necessary, of the elevated ash hoppers. It is not anticipated that any improvements would be required for ash removal vehicle access. Collected residues would be landfilled on the installation.

Air Pollution Control

Due to relative size differences, air pollutant emission requirements (particulates) for plant 3624 are different than for plant 4725. Because federal emissions regulations apply only to new sources, local (in this case, state) emissions standards apply.[10] Table 3 summarizes particulate emissions limitations in Alabama. Redstone Arsenal is located in a Class I (Madison) county. Boilers at steam plant 4725, which burn coal as specified in Section 5, are rated at approximately 109.9 million (Btu/hr) heat input (maximum). Using the formula,

$$E = 1.38\ H^{-0.44} \qquad \text{[Eq 1]}$$

where E = emissions in lb/10^6 Btu
H = heat input in 10^6 Btu/hr

the allowable particulate emissions for each boiler are calculated at 0.17 lb/million Btu per boiler. Similarly, for steam plant 3624, allowable particulate emissions are 0.22 lb/million Btu per boiler.

Sulfur oxide emissions would also be affected by state regulation. Madison County is classified as a Class II area for sulfur oxide emissions, which are limited to 4 lb (1.8 kg) of sulfur oxides (measured as SO_2) per million Btu of coal input.[11]

---

10 Environmental Protection Agency, "New Stationary Sources Performance Standards; Electric Utility Steam Generating Units," *Federal Register*, Part II, 40 CFR Part 60, June 11, 1979.

11 *Rules and Regulations* (Alabama Air Pollution Control Commission, September 1976).

Table 3

Allowable Particulate Emissions, Alabama
Emission Based on Heat Input*

Heat Input (Millions of Btu/hr)	Allowable Emission (lb/million Btu)	
	Class I County	Class II County
1	0.5	0.8
10	0.5	0.8
20	0.37	0.53
40	0.27	0.35
60	0.23	0.28
80	0.20	0.24
100	0.18	0.21
150	0.15	0.16
200	0.13	0.14
250	0.12	0.12
1,000,000	0.12	0.12

---

* *Rules and Regulations* (Alabama Air Pollution Control Commission, September 1976).

Based on the projected coal sulfur content of 1.7%, SO_x emissions, measured as SO_2, would be as follows:

Plant 4725:

109.9×10^6 (Btu/hr) x 4 (lb $SO_2/10^6$ Btu) = 439.6 (lb/hr)

(199.4 kg/hr) maximum SO_2 emissions

38 (1.7%) = 64.6 (lb SO_2/ton coal) = emission rate

64.6 (lb SO_2/ton coal) x 109.9×10^6 (Btu/hr) ÷ 14,090 Btu/lb

coal ÷ 2,000 (lb/ton) = 251.9 lb/hr (119.7 kg/hr) actual

SO_2 emissions

251.9 (lb/hr) (119.7 kg/hr) <439.6 (lb/hr) (119.7 kg/hr)

Plant 3624:

Allowable emissions = 263.8 lb SO_2/hr (119.6 kg/hr)

Actual emissions = 151.1 lb SO_2/hr (68.54 kg/hr)

Both plants would therefore be in compliance without SO_x controls.

Particulate emissions are not in compliance without some type of control equipment. Using traveling grate stoker equipment, uncontrolled particulate emissions from each plant would be:

Plant 4725:

[5 (3.4%)* x 109.9×10^6 (Btu/hr)] ÷ [14,090 (Btu/lb coal) x

2,000 (lb/ton)] = 66.3 (lb/hr) (30.1 kg/hr)

Plant 3624:

[5 (3.4%)* x 65.9×10^6 (Btu/hr)] ÷ [14,090 (Btu/lb coal) x

2,000 (lb/ton)] = 39.8 (lb/hr) (18.0 kg/hr)

---

* Probable coal ash content (see Section 5).

Allowable emissions are:

Plant 4725:

$$0.17 \text{ lb particulate}/10^6 \text{ Btu} \times 109.9 \times 10^6 \text{ (Btu/hr)} =$$

$$18.6 \text{ (lb/hr) (8.5 kg/hr)}$$

Plant 3624:

$$0.22 \text{ lb particulate}/10^6 \text{ Btu} \times 65.9 \times 10^6 \text{ (Btu/hr)} =$$

$$14.5 \text{ (lb/hr) (6.6 kg/hr)}$$

Consequently, 72% and 64% control efficiency must be effected for plants 4725 and 3624, respectively.

Referring to Table 4, it appears that adequate particulate control could be maintained through the use of low-resistance cyclone equipment at both plants.

Start-Up - Shakedown

Because energy production must continue during the reconstruction of both steam plants, start-up operations will be complicated. Normally, 2 to 3 months are scheduled for start-up and shakedown of new coal-fired industrial boilers. Experience to date with reconverted steam plants is insufficient to draw general conclusions. Assuming the boiler plants at Redstone fall into the upper range (i.e., 3 months), a total of 6 months of start-up and shakedown for each plant, or a total of 1 year for both, will be required.

Besides scheduling difficulties, start-up and shakedown operations cannot interfere with normal day-to-day plant activities. Because of the above constraints, and due to the uncertainties inherent in an estimation of this type, a conservative time period was selected. Total start-up and shakedown expense was projected to be 2.5 times that which would be expected of a comparable new facility.

Economic Analysis - First Costs

Table 5 summarizes the estimated capital expense of reconverting and rehabilitating steam plants 4725 and 3624 at Redstone Arsenal. Estimates are included for all equipment and services described in the preceding section. Total first cost for plant 4725 equaled $8.16 million. Total first cost for plant 3624 equaled $4.72 million. The total cost for both plants is $12.88 million, or about 50% of the projected cost of a new central steam plant. These estimates are in line with

Table 4

Range of Collection Efficiencies for Common Types of Fly Ash Control Equipment*

Type of Furnace	Range of Collection Efficiencies (%)			
	Electrostatic Precipitator	High-Efficiency Cyclone	Low-Resistance Cyclone	Settling Chamber Expanded Chimney Bases
Cyclone Furnace	65 to 99.5**	30 to 40	20 to 30	10**
Pulverized Unit	80 to 99.5**	65 to 75	40 to 60	20**
Spreader Stoker	99.5**	85 to 90	70 to 80	20 to 30
Other Stokers	99.5**	90 to 95	75 to 85	25 to 50

* U.S. Environmental Protection Agency, *Compilation of Pollutant Emission Factors,* Third Edition, Part A (August 1977).

** The maximum efficiency to be expected for this collection device applied to this type source.

Table 5

Rehabilitation/Reconversion Capital Cost Estimate

Item	Plant 4725	Plant 3624
	Cost ($) 1980	
Fuel Delivery:		
Truck Scales	50,000*	50,000*
Roadway Improvement	None	5,000
Total	50,000	55,000
Fuel Storage:		
Bulldozer	90,000	90,000
Building Relocation/Removal	25,000	None
Site Preparation	15,000	8,000
Bin Shakers (Optional)		
Total	130,000	98,000
Fuel Handling:		
Coal Crusher	315,000	185,000
Elevator System	231,000	126,160
Distribution Conveyer System	147,600	105,000
Total	693,600	416,160
Boiler Conversion:		
Oil Burners/Attachments Removed	176,000	125,000
Coal Feed Chutes Reattached	276,000	210,000
Spreader Stokers (Installed)	3,328,000	2,530,000
Stoker Auxiliary Equipment	738,000	558,000
Refractory Replaced	673,000	501,000
Steam Tubes Replaced	557,000	436,000
Boiler/Combustion Control System	287,000	220,000
Combustion Air Fan Overhaul	185,000	136,000
Total	6,220,000	4,716,000
Residue Handling:		
Ash Lock Renovation/Repair	190,000	71,000
Ash Conveyers Overhaul	80,000	73,000
Ash Elevation System Overhaul	150,000	84,400
Elevated Ash Hoppers Renovation	260,000	240,000
Ash Trucks	23,000	23,000
Total	703,000	491,400

Table 5 (continued)

Item	Cost ($) 1980 Plant 4725	Cost ($) 1980 Plant 3624
Air Pollution Control:		
Low-Resistance Cyclone	87,000	53,000
High-Efficiency Cyclone	135,000	85,000
Induction Fan	24,000	17,000
Subtotal	246,000	155,000
Start-Up	35,000	35,000
Shakedown	83,000	83,000
Grand Total	8,160,600	6,049,560

* Direct quote, Cardinal Scale Company.

other reported reconversion costs.[12] However, considering the age and condition of each plant, the costs listed in Table 5 are understood to represent a minimum.

Economic Analysis - Recurring Costs

As was the case with first costs, accurate estimation of recurring costs associated with boiler plant reconversion is hampered by a lack of previous industry experience. Recurring costs of this type are in general a function of investment in first costs (i.e., the more overhaul completed during rehabilitation, the less maintenance required in the future).

Table 6 presents a breakdown of recurring cost estimates derived from the minimum rehabilitation scenario described in Table 5. Consequently, Table 6 indicates a maximum recurring cost.

Labor costs were distributed among the various categories in proportion to the percentage of manpower consumed and weighted for relative wage differences. Results indicate that annual operating and maintenance costs for steam plant 4725 are 9% of rehabilitation (i.e., first) cost; for steam plant 3624, they are 8.5%. Expected recurring costs for new industrial coal-fired steam plants are normally 3% to 4.5% of the capital cost.[13]

Table 7 presents a summary of recurring cost estimates for major line items excluding a proportional labor distribution. Labor costs are instead developed as a separate expense.

---

12 S. A. Hathaway, et al., *Project Guidelines for Converting Army Installations to Coal Use*, Interim Report E-148 (CERL, March 1979).

13 S. A. Hathaway, et al.

Table 6

Rehabilitation/Reconversion Recurring Cost Estimate

Item	Annual Cost ($/yr) Plant 4725	Plant 3624
Fuel Delivery:		
Roadway/Scale Maintenance	2,000	2,000
Scale Operation	20,000	20,000
Total	22,000	22,000
Fuel Storage:		
Bulldozer Maintenance*	3,500	3,500
Bulldozer Operation	55,000	55,000
Site Maintenance	7,000	5,500
Total	65,500	64,000
Fuel Handling:		
Coal Crusher O&M	18,000	13,000
Elevator System O&M	14,800	11,700
Distribution Conveyer System O&M	11,000	8,400
Total	43,800	33,100
Boiler Conversion:		
Grate O&M	129,000	87,000
Fan O&M	67,000	48,000
Feedwater Preparation**	58,300	49,700
Combustion Controls	39,000	34,000
Total	293,300	218,700
Residue Handling:		
Ash Conveyer O&M	7,600	6,600
Ash Elevator System O&M	8,300	7,600
Ash Truck O&M	18,000	15,000
Ash Disposal O&M	6,500	4,800
Total	40,400	34,000
Air Pollution Control:		
Cyclone O&M	26,900	10,900
Residue Handling	12,000	7,200
Total	38,900	18,100

Table 6 (continued)

Item	Annual Cost ($/yr) Plant 4725	Plant 3624
Miscellaneous:		
Utilities	38,000	25,600
Water	21,200	16,900
Building Maintenance	97,000	60,000
General Maintenance	61,700	38,000
Total	217,900	140,500
Grand Total	721,800	530,400

* Average over 8-year life of equipment.

** Assumes 100% condensate return.

Table 7

Recurring Cost Summary -
Rehabilitation/Reconversion Alternative

Item	Quantity	Unit Cost	Annual Cost ($\$10^3$/yr)
---PLANT 4725---			
Labor	15	\$22,500/man-year*	337.5
Coal	19,500 tons	\$49/ton	955.5
Maintenance	5,000 hr	\$11/hr	55.0
Utilities	1.08×10^6	\$0.035/kWh	38.0
Water	10.0×10^6 kWh	\$0.21/gal	21.2
Total			1,407.2
---PLANT 3624---			
Labor	13	22,500/man-year*	292.5
Coal	13,260 tons	\$49/ton	649.7
Maintenance	3,800 hr	\$11/hr	41.8
Utilities	731,500 kWh	\$0.035/kWh	25.6
Water	8×10^6 gal	\$0.21/gal	16.9
Total			1,026.5

* Average yearly expense: wages plus fringe benefits.

4 NEW COAL-FIRED CENTRAL STEAM PLANT

As described in Section 2, a new, centrally located coal-fired steam plant replacing both plants 4725 and 3624 has received the most attention as a replacement system for Redstone Arsenal. The basic layout and design of this system is presented in the Black & Veatch report.[14] Rather than attempt to duplicate that effort here, only the major capital costs will be described. Several modifications are suggested to reduce the cost of air pollution control and boiler operation.

Fuel Delivery

The same fuel delivery considerations discussed in Section 3 are applicable here. At average steam load, between five and six coal trucks per day will deliver. During periods of maximum load, as many as eight trucks per day will arrive. Consequently, full-time staffing at the scale house is not required. As was the case with the satellite plants, the bulldozer operator will double as gate operator.

Fuel Storage

The proposed central steam-generating site will utilize both indoor and outdoor coal storage. Because the site is presently undeveloped, adequate area for outdoor storage is not a constraint. The considerations pertaining to establishment of coal storage, presented in Section 3, are also valid for this facility. Coal pile management can still be accomplished by one bulldozer. Indoor storage will be addressed in a later section.

Fuel Handling

Due to the varying particle size requirements of different stoker equipment, the fuel handling (i.e., size reduction) operations at the larger central steam plant will be more complex than at the smaller regional plants. Suspension-fired, pulverized coal boilers, for instance, require that coal be ground to the consistency of flour (i.e., 50% passing 200 mesh). Spreader stokers, utilizing a combination of suspension and grate firing, require coal to be crushed to only a nominal 0.5-in. (1.3-cm) size. Selection of fuel handling equipment is therefore highly

---

14 Black & Veatch Consulting Engineers, *Basewide Energy Systems Plan - Total Energy and Selective Energy*, Draft Final Report DACA01-77-C-0094, Vol. 1 (Mobile District Corps of Engineers, October 1979).

dependent upon boiler type. As currently envisioned, pulverized coal boilers will be installed at the new central plant. This analysis considers coal for both suspension boilers and spreader stoker equipment for reasons described in the air pollution section.

Coal from the outdoor storage piles will be moved into the crusher loading pit by bulldozer. Gravity-fed into the crusher for size reduction, the powdered/granular coal will be transferred to indoor overhead coal storage bunkers either pneumatically (powdered) or via bucket elevator and conveyer (granular). Energy requirements for the pulverizer (ball mill or hammer mill) are high (15 kWh/ton coal), as is the associated maintenance expense. In contrast, stoker coal may require only screening to eliminate oversized coal chunks. At worst, a crusher is required. Typical coal crusher energy consumption is <1 kWh/ton coal.[15]

Site Development and Plant Installation

This alternative involves a newly constructed coal fired steam plant complex. A 3/4-mile (1.2-km) access road capable of carrying highway axle weights (22,000 lb) (9,979 kg) will be required. Site grading, utility and sewer lines, as well as two 1-mile steam mains, will be connected to the base stream grid. Approximately 3 acres (12,141 m^2) will be dedicated to coal storage, with the attendant improvements required for drainage and access.

A boiler plant building, of approximate dimensions 200 ft x 100 ft x 50 ft (61 m x 30 m x 15 m), will then be constructed using prestressed concrete slabs. Provision will be made for the necessary offices, control rooms, locker rooms, etc.

The boilers envisioned for this facility are field-erected. As currently envisioned, they would be suspension-fired, and utilize pulverized coal.[16] Additionally, the boiler size specified in the most recent feasibility report is just sufficient (258×10^6 Btu/hr) to be subject to federal NSPS air pollution standards (250×10^6 Btu/hr).

---

15 *Jeffrey/Dresser Catalogs*, "Coalbusters," Technical Bulletin 1145, 1978.

16 Black & Veatch Consulting Engineers, *Basewide Energy Systems Plan - Total Energy and Selective Energy*, Draft Final Report DACA01-77-C-0094, Vol. 1 (Mobile District Corps of Engineers, October 1979).

Air Pollution Control

Significant savings in air pollution control expense, both for first and recurring costs, can be effected by (1) reducing each boiler capacity to below the 250 x 10^6 (Btu/hr) heat input limit, and (2) utilizing spreader stoker grates instead of pulverized coal suspension firing.

As outlined earlier, State of Alabama air pollutant emission limitations applicable to Redstone Arsenal are calculated for particulates by using Equation 1. Assuming a maximum boiler rating of 240 x 10^6 Btu/hr (a downgrading of 7%, or from 192,000 lb steam/hr to 178,500 lb steam/hr), allowable emissions would be 0.12 lb/10^6 Btu, or 29.7 lb/hr (13.5 kg/hr), at system capacity. Similarly, sulfur oxide emissions limitations specific to Redstone Arsenal are 4.0 lb/10^6 Btu heat input (expressed as SO_2). At this rate, the coal to be used would be compliance coal (i.e., at a sulfur content of 1.7%), and the maximum SO_2 emissions would be 2.3 lb/10^6 Btu.

Spreader stokers generate considerably less fly ash than do suspension-fired units. Additionally, significant energy savings result from the relaxed coal preparation (size reduction) requirements. Uncontrolled emissions from spreader stoker-fired equipment would be 157 lb/10^6 Btu.[17] By utilizing a low-resistance cyclone, followed by a high-efficiency cyclone, controlled emissions could be expected to be in compliance (0.05 lb/10^6 Btu) (see Table 4).

Start-Up - Shakedown

Because a new central plant would be independent of existing steam production facilities, start-up and shakedown activities would not interfere with day-to-day operations. Should downtime occur after transfer of primary steam production responsibility to the new plant, the existing facilities would be available for backup, thus providing redundancy.

Many of the current Redstone operating personnel have coal-fired boiler experience, a factor which should facilitate training and shakedown. Since there are no unusual factors which tend to complicate start-up and shakedown activities, the industry average start-up time of 2.5 months is assumed.[18]

---

[17] U.S. Environmental Protection Agency, *Compilation of Pollutant Emission Factors*, Third Edition, Part A (August 1977).

[18] "Coal: Economical Fuel for Industry?," *The 1978 Energy Handbook* (McGraw-Hill, 1978), pp 101-107.

Economic Analysis - First Costs

Both first and recurring costs of cyclone equipment are considerably less than for alternate fly ash control devices (e.g., electrostatic precipitators or bag houses). The use of a spreader stoker, relative to pulverized coal suspension firing, compromises both combustion efficiency and operating flexibility to a slight degree. At Redstone Arsenal, these factors are not critical, and the reduced air pollution control costs more than it compensates for this loss.

Major cost items associated with coal-fired steam plant construction are as follows:

1. Boiler(s) (tubes, refractory, shell).
2. Grate mechanism.
3. Stacks(s).
4. Fans.
5. Controls.
6. Coal bunker.
7. Coal feed mechanism.
8. Feed water treatment.
9. Ash removal system.
10. Air pollution control.

The recent, previously noted Black & Veatch feasibility report, dealing with the establishment of a new, centrally located coal-fired steam plant at Redstone Arsenal, arrived at a cost estimate of $60.2 million (1979 dollars) for the recommended system. This estimate included some electrical generating capability. Also included was an oil-fired boiler to be used as backup. However, plants 4275 and 3624 could also be employed in that capacity.

The Black & Veatch report does not break out cost items in any way. Fourteen options, ranging from $30.6 million to $122.4 million, were presented. The level of precision in the report was far in excess of the scope of work of this project; consequently, the analysis presented here will be in the form of a check of that data.

The capital cost of new stoker-fired boilers and auxiliary equipment in the range of 100,000- to 200,000-pph steam is $40 to $47/pph (Figure 11). The basis for this estimate[19] is:

1. A condensate/feedwater system with two 100% capacity pumps, a make-up water softener, and chemical feed capability, plus a

---

[19] B. D. Coffin, "Estimate the Cost of Your Next Coal-Fired Industrial Boiler Plant," *Power*, Vol. 121, No. 10 (October 1977), pp 28-29.

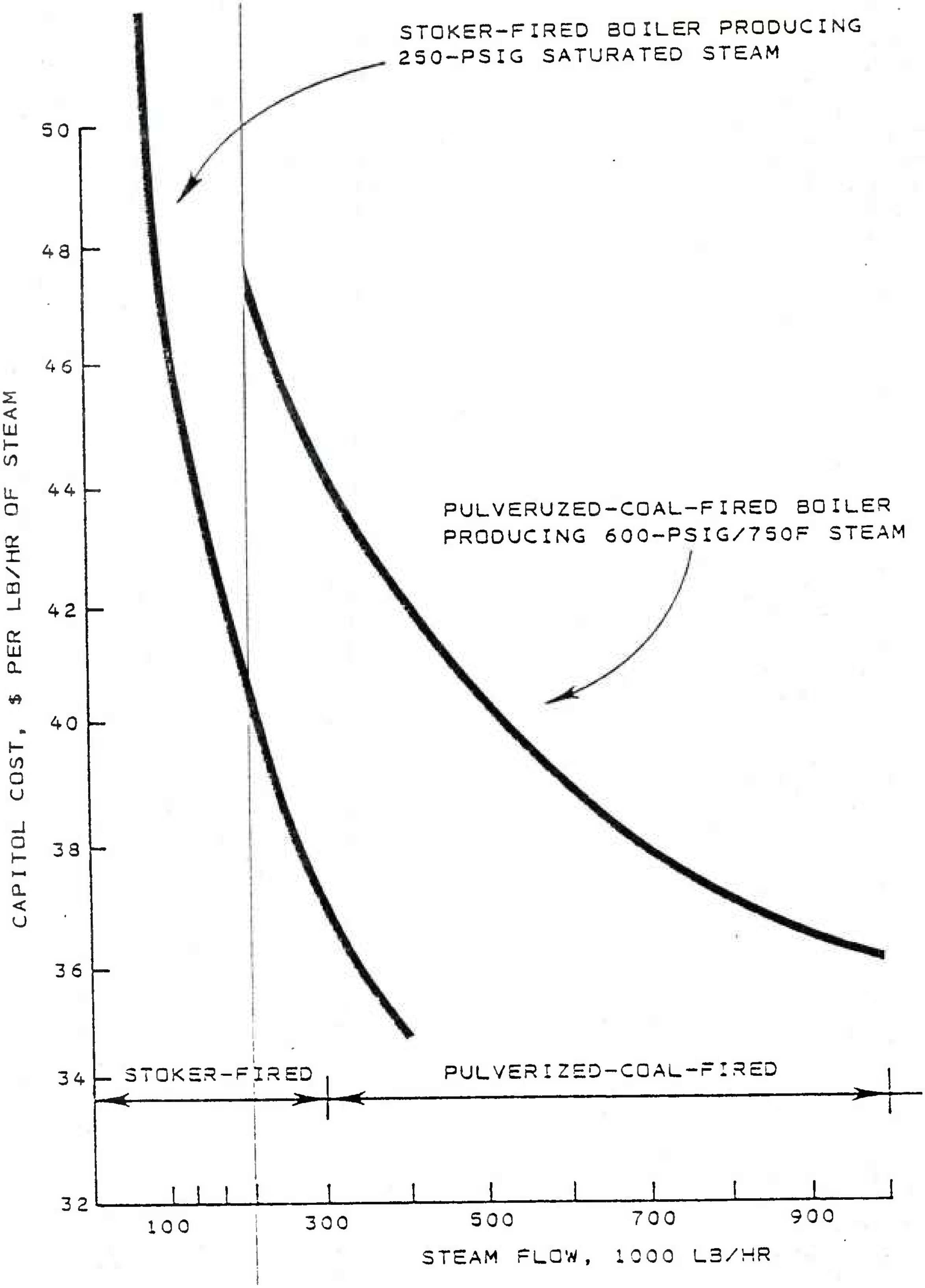


Figure 11. Boiler system capital cost, stoker-fired and pulverized coal-fired equipment.

continuous-blowdown flash tank and a condensate heat recovery unit.

2. Bucket elevator coal handling.

3. Electric-motor-driven auxiliaries complete with motor-control centers.

4. Instrument and plant air systems.

5. Combustion and feedwater controls.

6. 82%-efficient boiler equipped with a mechanical dust collector and an economizer.

For two 175,000-pph boilers, capital costs would be $17.64 million (1976). Correcting to 1980 dollars, this estimate increases to $21.5 million.[20] The total cost estimate increases by approximately $4 million with the addition of such site-related factors as:

1. Site preparation and grading.
2. Access roads.
3. Ash disposal beyond the storage silo.
4. Coalyard preparation, reclaim system, and drainage control.
5. Raw water supply, pumping, and storage.
6. Steam and condensate piping beyond the powerhouse walls.
7. Boiler house.

The total cost estimate for this alternative is summarized in Table 8.

The capital cost estimate presented in Table 8 compares favorably with the economic analysis in the Black & Veatch report. Therefore, the total first cost of establishing a new central steam plant at Redstone Arsenal can be reliably estimated in the range of $26 million to $30 million.

Economic Analysis - Recurring Costs

Annual operating and maintenance costs can be broadly categorized as:

1. Fuel handling.
2. Boiler operation.
3. Residue handling.
4. Air pollution control.

---

20 *1980 Dodge Guide (Public Works and Heavy Construction)*, McGraw-Hill Information Service Company.

Table 8

New Coal-Fired Central Steam Plant
Capital Cost Summary

Item	Cost ($)
Boiler System (two at 175,000 pph)	21.5×10^6
Site Preparation and Grading*	180,000
Access Roads*	25,000
Ash Disposal	800,000
Coalyard Preparation*	275,000
Water Supply	175,000
Steam Distribution	680,000
Utilities	300,000
Boiler House	1.5×10^6
Total	25.4×10^6

* *1980 Dodge Guide (Public Works and Heavy Construction)*, McGraw-Hill Information Service Company.

These cost items are presented in Table 9. Labor costs are distributed among the various categories in proportion to the percentage of manpower consumed and weighted for relative wage differences.

As indicated in Table 9, recurring costs for the large central plant are in many instances less than for either of the smaller rehabilitated plants. Recurring costs for this alternative constitute 3.4% of the capital investment, as compared to approximately 9% for the rehabilitation option.

Table 10 presents a summary of estimated recurring costs, including costs for labor and fuel. Assuming an economic life of 20 years for each alternative, the following comparison of present worth is presented:

	Present Worth ($\$x10^6$)	
Interest Rate (%)	Rehab/Reconvert	New Plant
10	24.9	32.1

Thus, based on economics alone, the rehabilitation/reconversion alternative appears to be the most attractive.

Table 9

New Coal-Fired Central Steam Plant
Recurring Cost Summary

Item	Annual Cost ($/yr)
Fuel Delivery:	
Roadway/Scale Maintenance	8,000
Scale Operation	25,000
Total	33,000
Fuel Shortage:	
Bulldozer Maintenance	5,000
Bulldozer Operation	90,000
Site Maintenance	23,000
Total	118,000
Fuel Handling:	
Coal Crusher O&M	37,000
Bucket Elevator System O&M	15,000
Distribution Conveyer System O&M	12,700
Total	64,700
Boiler Operation:	
Grate O&M	239,000
Fan O&M	92,000
Feedwater Preparation*	67,500
Combustion Controls	45,000
Total	443,500
Residue Handling:	
Ash Conveyer System O&M	8,800
Ash Elevater System O&M	9,600
Ash Truck O&M	22,000
Ash Disposal O&M	13,000
Total	53,400
Air Pollution Control:	
Cyclone O&M	47,000
Residue Handling	15,000
Total	62,000

Table 9 (continued)

Item	Annual Cost ($/yr)
Miscellaneous:	
Utilities	57,000
Water	18,000
Building Maintenance	19,000
General Maintenance	20,000
Total	84,000
Grand Total	888,600

* Assumes 100% condensate return.

Table 10

Recurring Cost Summary -
New Coal-Fired Central Steam Plant

Item	Quantity	Unit Cost	Annual Cost ($\$10^3$/yr)
Labor	22	22,500/man-year*	495
Coal	32,760 tons	\$49/ton	1,605
Maintenance	2,200 hr	\$11/hr	24.2
Utilities	1.63×10^6 kWh	\$0.035/kWh	57.0
Water	8.5×10^6 gal	\$0.21/gal	18.0
Total			2,199.2

* Average yearly expense: wages plus fringe benefits.

5 COAL CONVERSION FUEL CONSIDERATIONS

The motivation to convert Army installations from oil- or gas-based energy systems arises from an attempt to reduce dependence on foreign oil, and thereby limit vulnerability to supply disruption. Any domestically produced fuel, besides oil and gas, would help to attain these goals.

Because of its abundance, coal has been targeted as the primary fuel to replace oil and gas. There are a number of sources of coal within economic transport distance of Redstone Arsenal. Before 1972, when the principal fuel used at Redstone was coal, supplies were obtained from deposits near Jasper, approximately 115 miles from Redstone. This coal is typical of northern Alabama bituminous deposits ranging from 12,000 to 15,500 Btu/lb, 0.6 to 2.0% sulfur, and 2 to 15% ash. The price of northern Alabama coal currently ranges from $25 to $50 per ton, lower sulfur coal commanding the higher price.

In order to determine the characteristics of coal currently available for use at Redstone, an inquiry was made at the Defense Logistics Agency, Defense Fuel Supply Center. Based on responses to a request for bids for coal supplies to Anniston Army Depot, Alabama (85 miles from Redstone Arsenal), the information in Table 11 was obtained. The mean values indicated that a coal containing 2.9% ash and 0.8% sulfur could be obtained, with a mean heating value of 14,660 Btu/lb. The apparent low bidder, transportation notwithstanding, would be Southeastern Company, in Natural Bridge, Alabama.

The distance from Natural Bridge to Redstone is 95 miles. This coal has the following characteristics:

1. 3.4% ash.
2. 1.7% sulfur.
3. 14,090 Btu/lb.
4. $42/ton.

Transportation expense would be $7/ton/100 miles shipped. All calculations performed in the course of this study were based on the above data.

At $49 per ton (delivered), the coal use for Redstone Arsenal would cost:

$$32{,}760 \text{ tons/yr} \times \$49/\text{ton} = \$1.6 \text{ million}$$

This compares with present fuel oil expense as follows:

$$152{,}000 \text{ bbl/yr} \times \$21/\text{bbl} = \$3.2 \text{ million}$$

Table 11

Coal Characteristics - Bids to Anniston Army Depot, Alabama

Contractor	Shipping Point	Coal Size	Moisture Average (%)	VIM Average (%)	ASH Average (%)	Dry Sulfur Average (%)	Dry Btu Average (%)	Dry A.S.T.	FOB Mine Price	FRT Truck Rate	Distance (mi)	FRT Rail Rate	RR	Mine
Mitchell Energy	Sipsy, Alabama	1 ¼" x ¼"	4.3	37.1	2.7	0.8	14,618	2,637	$52.25	$5.75	85			McWane, Alabama
Drummond Coal Co.	Breman, Alabama	1 ¼" x ¼"	3.7	38.2	2.5	0.7	14,670	2,450	50.00	6.00	104			Arkadelphia, Alabama
Leslie B.	Dixiana, Virginia	1 ¼" x ¼"	5.9	35.8	2.5	0.7	15,040	2,630	52.00			$10.65	SOU	Flat Gap, Virginia
Island Creek	Price, Kentucky	1 ¼" x ¼"	3.8	40.3	3.1	0.8	14,674	2,560	48.00			12.30	C&O	Wheelwright, Kentucky
Mitchell	Sipsy, Alabama	1 ¼" x ¼"	3.4	37.4	2.4	0.7	14,694	2,750	57.00	5.75				McWane, Alabama
Berle	Dixiana #1, Virginia	1 ¼" x ¼"	5.9	35.8	2.5	0.7	15,040	2,630	48.00			9.95	SOU	Flat Gap, Virginia
Diana Fuels	Mabley, W. Virginia	1 ¼" x ¼"	2.4	36.6	3.3	0.6	14,880	2,910	38.00			14.10	N&W	Red Jacket, W. Virginia
Leslie B.	Clinchmore, Tennessee	1 ¼" x ¼"	4.2	40.8	4.8	0.7	14,270	2,680	55.25			12.04	TN	Clinchmore, Tennessee
Southeastern Co.	Natural Bridge, Alabama	1 ¼" x ¼"	6.2	39.8	3.4	1.7	14,090	2,180	42.00	7.00	100			Drummond Coal Co., Alabama
Hallmark and Son	Sipsy, Alabama	1 ¼"	4.2	37.3	2.8	0.8	14,619	2,627	52.45	6.00	95			Sipsy, Alabama
Drummond Coal Co.	Arkadelphia, Alabama	1 ¼" x ¼"	3.7	38.2	2.5	0.7	14,670	2,450	50.00	6.50				Arkadelphia, Alabama
MEAN			4.3	37.9	2.9	0.8	14,660	2,591	49.54					

Consequently, coal conversion will save approximately 50% of the current base fuel bill.

<u>Alternate Fuels</u>

As an alternative to coal conversion, the possibility of utilizing a nonfossil fuel at Redstone Arsenal was investigated. Possible fuels included:

1. Solid waste.
2. Hog fuel.
3. Peat.
4. Bio-gas.

Due to the large percentage of office waste generated at Redstone, solid waste characteristics are more attractive for energy recovery than typical municipal refuse would be. However, the waste volume is insufficient (less than 100 tons per day) to justify the expense of solid waste processing for coal co-firing.[21]

Alternatively, the implementation of resource recovery using modular incineration with waste heat recovery is very attractive, and in fact is being pursued at Redstone. Design of a system consisting of two package incinerators, sized to handle 60 to 80 tons of waste per day, is in progress. Steam produced from these units would be used in an area not presently served by steam plants 4725 or 3624.

Hog fuel or wood waste is used to fuel industrial boilers in many areas of the country, particularly the Pacific Northwest (lumber mills have for many years employed hog fuel-fired boilers). Consequently, the technology for wood combustion is well developed.

During the course of site investigations, wood waste availability in the Huntsville area was researched. Lumbering activity is not as extensive in northern Alabama as on the other side of the Appalachian Mountains in Georgia and North Carolina. One particle board facility in the Huntsville-Decatur area consumes most local waste wood, and imports additional supplies from as far as 150 miles during certain periods of the year. Waste wood for use as hog fuel is therefore not considered abundant in the Huntsville area.

---

21 SCS Engineers, Inc., *Small-Scale and Low-Technology Resource Recovery Study* (Municipal Environmental Research Laboratory, 1979).

Peat is not presently used for fuel in the United States, although it is used extensively in the Soviet Union.[22] Peat is rated at approximately 3,600 Btu/lb after drying (25% moisture), or about 1/4 the value of coal. Although possible peat deposits could be exploited for use at Redstone, no information is available on their extent or cost. Peat use was therefore judged to be an impractical option.

Bio-gas can be derived either from specially constructed digesters or from landfills. In either case, a blend of methane, carbon dioxide, nitrogen, water vapor, and trace gases results in a heating value ranging from 200 to 600 Btu/scf.

Use of digesters provides a greater degree of control over the quantity and quality of gas available for combustion compared to landfill extraction. Sewage sludge can also be utilized in the process. The quantity of wastes available for charging gas digesters at Redstone, however, is not sufficient to fuel even one existing boiler at steam plants 3624 or 4725. A maximum of 100 tons per day of waste, which produces approximately 60,000 scf of gas, is available (assume that gas equals 600 Btu/scf, and that 1 lb [0.45 kg] of waste generates 3 scf [0.08 m^3] of gas).[23] This quantity of gas (equivalent to 360 x 10^6 Btu) would operate the smallest boiler at plant 3624 only 5.4 hr per day at maximum load. Additionally, 60 to 80 tpd of waste are not available for digestion, since it has been dedicated to fuel two planned modular incinerators.

Bio-gas is potentially available at Redstone from an on-base landfill. Estimates of the quantity of recoverable gas from this fill indicate that insufficient volumes are available for steam plant operation. The Redstone landfill contains approximately 0.75 x 10^6 in-place tons of refuse. Assuming a generation rate of 0.15 ft^3 of methane per pound of in-place refuse per year, the production rate at the Redstone landfill could potentially be as high as 52,000 ft^3/hr (1,473 m^3/hr). This gas is rated at 500 Btu/scf, and would fuel the smallest boiler at plant 3624 for less than 3 hr per day at maximum load. Although one of the smaller boilers on base could possibly be converted to fire landfill gas, a complete engineering investigation needs to be completed to assess the technical and economic feasibility of this option.

The use of alternate fuels in the heating and cooling system at Redstone Arsenal is neither technically nor economically feasible. Quantities available are insufficient to supply a significant portion of the installation's energy (steam) demand. Possibly some of the less

---

22 R. L. Loftness, *Energy Handbook* (Van Nostrand Company, 1978).

23 U.S. Environmental Protection Agency, *Resource Recovery Plant Implementation/Technologies* (SW-157.2), 1977.

developed areas at Redstone, served by their own small boilers, could be converted to utilize alternate fuels. Waste incineration with heat recovery is already planned and will consume over 50% of the available solid waste.

6 GUIDELINES APPLICABILITY

CERL Interim Report E-148, Project Development Guidelines for Converting Army Installations to Coal Use, was used extensively in the course of this study. During each project phase, the applicability of E-148 was evaluated for completeness and accuracy (with respect to cost information). In general, E-148 was found to adequately address the relevant factors affecting Army scale coal conversion activities. Three areas were identified in which a slight expansion of the report scope would provide additional clarification and applicability: (1) preliminary conceptual system design, (2) preliminary identification of limiting constraints, and (3) expanded referral to technical references.

At Redstone Arsenal, certain key factors made selection of one system preferable over other alternatives; this would possibly be the case at other Army installations. The controlling parameters were found to be:

1. Status of existing system.
2. Profile of energy demand.
3. Fuel characteristics.

Consequently, a preliminary conceptual system can be easily developed utilizing these factors and any significant site-specific parameters. Subsequent investigation may indicate that a different approach is desirable; however, a preliminary determination based on the above guidelines should prove accurate.

Preferably, the preliminary conceptual design guidelines would be presented in a format suitable for use by persons without extensive technical background. Figure 12 is an example of such a presentation. Ideally, a flow chart of this type could be developed for application to a wide variety of Army installations. An associated work sheet for development of preliminary project data would also facilitate design efforts.

There are a number of constraints associated with the installation and operation of coal-fueled, power-generating facilities which limit their applicability. Most of these constraints are addressed in E-148; however, it would still be beneficial to summarize them for ease of reference.

A good example of a limiting parameter is air pollutant emission regulations. In the South Coast Air Basin of California, for example, coal conversion would not likely be permitted regardless of control equipment. Another example of a possible limiting factor is fuel availability. A brief listing of the major limiting parameters and their constraints could save substantial wasted effort. An example list is presented in Table 12.

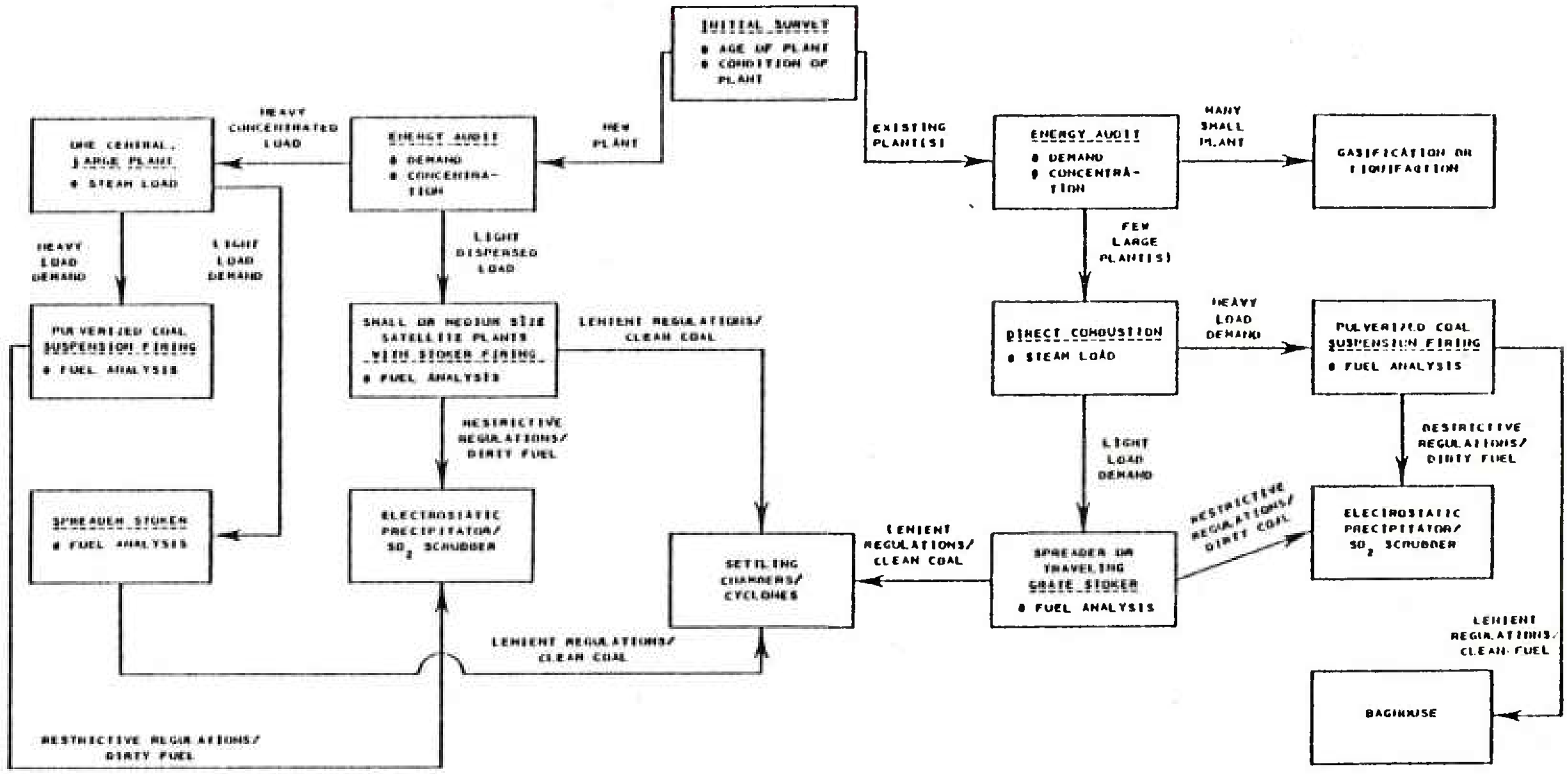


Figure 12. Preliminary conceptional design, coal conversion.

Table 12

Limiting Parameters, Coal Conversion at Army Installations

Parameters	Constraint
Plant Site	• Sufficient area must be available close to steam lines and access roads (rails).
Fuel Availability	• Alternate fuel must be available in sufficient quantity at economic price for the life of the plant.
Air Pollution Control Requirements	• Applicable permitting authorities must be willing to permit plant for operation.
Residue Disposal	• Appropriate landfill must be available for disposal of system wastes.

The scope of E-148 is to serve as an introduction rather than a complete guide to coal conversion. Although a number of excellent references are listed in E-148, an expanded bibliography would facilitate and standardize project development. Cost data presented in E-148 is necessarily vague; wide cost ranges are necessitated by the many diverse factors which impact project economics. For example, flue gas desulfurization sludge disposal systems are reported to cost (capital) from $2,000,000 to $10,000,000. This represents an "order of magnitude" estimate, and should be reinforced by adequate references.

In summary, E-148 provides a comprehensive introduction to Army scale coal conversion activities. All major factors affecting project development are addressed. The report progresses logically, and is easily understood. Cost estimate ranges were found to compare favorably with other published information.

7 CONCLUSIONS AND RECOMMENDATIONS

Conclusions

Without extensive overhaul, the present steam generation facilities (plants 4725 and 3624) at Redstone Arsenal will be in need of replacement within 3 to 7 years. Consequently, in order to avoid the double expense of constructing a new facility and rehabilitating existing equipment (or risking service breakdowns), preliminary efforts must be continued toward a replacement system.

Conversion of the heating and power system at Redstone to coal as a primary fuel is technically and economically feasible. Direct combustion technologies are the most attractive options. Rehabilitation and reconversion of existing steam plants present the lowest first cost option. However, construction of a new central steam plant is the least complex and most reliable option, has the lowest recurring costs, and provides the greatest energy efficiency and environmental protection.

Alternate fuel use is not practical for large-scale energy generation at Redstone. However, its use would be practical for small-scale, localized steam production.

CERL Interim Report E-148, Project Development Guidelines for Converting Army Installations to Coal Use, is a valuable reference for initiation of project developers in the problems and considerations associated with coal conversion. This document is comprehensive and progresses in a logical manner. Several minor additions are recommended.

Recommendations

Work should continue toward the design of an improved energy production system at Redstone Arsenal. A comprehensive survey of existing steam plants 4725 and 3624 should be initiated to determine the extent of rehabilitation required to prolong the life of these plants for a minimum of 20 years. Refined cost estimates should be prepared for more precise comparison of rehabilitation and new construction.

Use of pulverized coal boilers in the new facility design should be reevaluated. Specifically, boiler size and type should be reevaluated with respect to air pollution control requirements.

Use of waste materials as fuel should be considered for areas remote from steam plants 4725 and 3624. In particular, implementation of modular incineration with waste heat recovery should be expedited, and the potential of energy recovery from landfill gas investigated.

Minor additions to CERL Interim Report E-148 should be considered in order to summarize and clarify the guidelines presented in that document.

CITED REFERENCES

Black & Veatch Consulting Engineers, *Basewide Energy Systems Plan - Total Energy and Selective Energy*, Draft Final Report DACA01-77-C-0094, Vol 1 (Mobile District Corps of Engineers, October 1979), pp 1-51.

"Coal: Economical Fuel for Industry?," *The 1978 Energy Handbook* (McGraw-Hill, 1978), pp 101-107.

"Coalbusters," *Jeffrey/Dresser Catalogs*, Technical Bulletin 1145, 1978.

Coffin, D. B., "Estimate the Cost of Your Next Coal-Fired Industrial Boiler Plant," *Power*, Vol 121, No. 10 (October 1977), pp 28-29.

Coles, W. F., and J. T. Steward, *Considerations When Converting Industrial Plants to Coal Firing* (presented at The Industrial Power Conference, October 24-26, 1977).

Hathaway, S. A., et al., *Project Development Guidelines for Converting Army Installations to Coal Use, Interim Report E-148 (CERL, March 1979).*

Honig, E. M., Jr., and S. A. Hathaway, *Application of Modern Coal Technologies to Military Facilities, Volume I: Summary of Findings*, Interim Report E-130 (CERL, May 1978).

Loftness, R. L., *Energy Handbook* (Van Nostrand Company, 1978).

Rules and Regulations (Alabama Air Pollution Control Commission, September 1976).

SCS Engineers, Inc., *Small-Scale and Low-Technology Resource Recovery Study* (Municipal Environmental Research Laboratory, 1979).

Streets, D. G., and T. A. Speciner, *Issues Relating to New Source Performance Standards for Industrial Steam Generators*, Technical Memo ANL/EES-TM-54 (Argonne National Laboratory, June 1979).

U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Third Edition, Part A (August 1977).

U.S. Environmental Protection Agency, "New Stationary Sources Performance Standards; Electric Utility Steam Generating Units," *Federal Register*, Part II, 40 CFR Part 60, June 11, 1979.

U.S. Environmental Protection Agency, *Resource Recovery Plant Implementation/Technologies* (SW-157.2), 1977.

1980 Dodge Guide (Public Works and Heavy Construction), McGraw-Hill Information Services Company.

UNCITED REFERENCES

Coffin, D. D., "Estimating Capital and Operating Costs for Industrial Steam Plants," *Power* (April 1979).

Construction Criteria Manual, Technical Report DOD 42701-M, October 1972.

Dimitry, P., et al., "Emission Control for Industrial Coal Fired Boilers," *Combustion* (January 1980).

Robert Snow Means Company, Inc., *Building Construction Cost Data, 1980*, 38th Annual Edition.

Robert Snow Means Company, Inc., *Mechanical and Electrical Cost Data, 1980*, 3rd Annual Edition.

Steam: Its Generation and Use, 39th Edition (Babcock and Wilcox, 1978).

APPENDIX B

POWER PLANT COAL CONVERSION STUDY -- DIRECT COMBUSTION, LIQUEFACTION, GASIFICATION: UNITED STATES ARMY ARSENAL, PICATINNY, NJ

PREPARED UNDER

Purchase Order DACA 88-79-M-0254

by

POPE, EVANS AND ROBBINS

TABLE OF CONTENTS

1.0 INTRODUCTION

The United States Army Construction Engineering Research Laboratory has been developing a considerable data base for conversion to coal as the primary fuel at U.S. Army facilities. This study forms a part of that continuing effort. The scope of this study is to assess the technical and economic feasibility of converting the heating and power systems to coal as the primary fuel at the United States Army Arsenal at Picatinny, New Jersey. Oil firing capability would be retained to assure operation if coal became unavailable for a brief time.

Picatinny Arsenal is a critical facility supporting vital elements of United States Army weapon programs. Manufacturing operations have been reduced over the last several years with a greater emphasis on research and development. This change is reflected in the steam and electric requirements of the base.

The Arsenal power plant has three boilers operating at 420 psig and 650°F. Two are rated at 160,000 lb/hr and were converted from an original pulverized coal firing system to their current oil/gas regime; these boilers were manufactured in 1943. The third boiler, rated at 50,000 lb/hr, manufactured in 1971, is a packaged oil fired unit. The power plant also has three turbine generators. Two, rated at 3,000 kW each, are of the double automatic extraction-condensing type. Extraction pressures are 125 psig and 60 psig. These were manufactured in 1941 and 1953. The third turbine, rated at 1,500 kW is of the single extraction type at 125 psig, manufactured in 1937; it was decomissioned because of the improved efficiency of the newer turbines and the decreasing need for the higher pressure steam.

There are two sources of electric power for the facility: (1) purchased power from Jersey Central Power and Light Company and (2) the Arsenal Power Plant at Building 506. Currently the facility operates with significant condensing generation and provides base load operation; the utility supplies peak demands.

Consideration in this study is given to both current and advanced coal systems including direct combustion (in suspension, on a grate and fluidized bed combustion) and production and firing of gas and liquid derived from coal. Three coal conversion alternatives are analyzed and evaluated. Advanced technologies have been limited to those that would be suitable for design within the next two years, as operating plants and not as demonstration projects.

Historic fuel and steam usage patterns have been established and projections of future use have been made. Due to the changing function of Picatinny Arsenal, a reduction in both peak and average loads is anticipated. Table 1-1 shows current and project load and fuel requirements.

In reviewing the possibilities of coal conversion, the existing plant, equipment and site must be evaluated and alternatives sought, where necessary. These evaluative factors are discussed in Section 2.0 of this report. Section 3.0 deals with the application of identified technologies to a specific site at the Arsenal. The economic analysis is provided in Section 4.0.

Current literature has been reviewed in preparation of this report. A bibliography is appended.

TABLE 1-1

STEAM AND FUEL REQUIREMENTS

I. STEAM			
A. Current			
Annual	1.24×10^9 lb/year		
Peak	212,000 lb/hr		
Average	140,000 lb/hr		
B. Projected			
Annual	1.04×10^9 lb/year		
Peak	200,000 lb/hr		
Average	120,000 lb/hr		
II. FUEL*			
A. Current		Oil	Coal
Annual		10,700,000 gal/yr	65,000 tons/yr
Peak		1,830 gal/hr	11 tons/hr
Average		1,210 gal/hr	7.3 tons/hr
B. Projected			
Annual		9,000,000 gal/yr	55,000 tons/yr
Peak		1,730 gal/hr	10.4 tons/hr
Average		1,040 gal/hr	6.3 tons/yr

*Based on fuel oil at 145,000 Btu/gal, and coal at 12,000 Btu/lb.

2.0 GENERAL DISCUSSION OF OPTIONS

The desirability of converting to coal from gas or oil thereby extending natural resources and reducing dependency on imported fuel is well established. This Section presents a general discussion of conversion, with some reference to the requirements at Picatinny Arsenal. Section 3.0 discusses the specifics of conversion at the Arsenal. The feasibility of such a conversion requires rigorous investigation of alternatives before an assessment can be made. While many alternatives exist, there are three major conceptual methods for deriving usable energy from coal:

- direct firing;
- conversion of coal to gas with subsequent firing;
- conversion of coal to liquid with subsequent firing.

An assessment of the use of these methods must take into account, in addition to the capital and operating costs, the following factors:

- ability of the process to meet energy demand efficiently;
- equipment redundancy in existing plant to allow continued operation during modification;
- ability of existing equipment to be retro-fitted;
- available area within the existing plant to allow for conversion;
- available area around the existing plant for storage and coal handling.

Each of the evaluative factors affect the overall assessment differently. For example, should an existing plant not be large enough to allow for a conversion to a specific process, this would be of major concern. This concern would be lessened if an alternate site would be found and almost eliminated if a suitable area existed adjacent to the present plant to allow for efficient conversion. All of the factors have this interrelationship, with the exception of the first: the ability of the method to meet the energy demand efficiently. Where the inherent nature of process requires fuel production well in excess of demand, that process cannot be considered. Of the three methods reviewed, only direct-firing of coal has both been historically proven and can be sized to produce steam in the range required at the Picatinny Arsenal. Gasification of coal, in its low-Btu and medium-Btu forms can also be sized to efficiently meet energy demand, but is only currently establishing an operating record. Liquefaction of coal requires a facility of relatively large size to operate efficiently; an energy demand in the range of that required at the Picatinny Arsenal would not be expected to operate efficiently for any long term. When this factor is coupled with the state-of-the-art of liquefaction as a developing technology, further consideration of converting coal to liquid fuel at the Arsenal must be eliminated. Should a community or utility sized plant be considered in the future, assuming other users would be interested in pooling resources, this technology might be reinvestigated.

2.1 Equipment Redundancy

The existing plant must be reviewed from several points-of-view. Perhaps the most important aspect is the redundancy of existing major equipment. The desired redundancy is such that, for example, one boiler can be removed from service for the period of time required for retrofitting or replacement without adversely affecting the energy supply to the facility.

The Picatinny Arsenal Power Plant contains two 160,000 lb per hour boilers and one 50,000 lb per hour boiler. The peak demand at Picatinny is 212,000 lbs per hour and the average demand is 140,000 lbs per hour. The projected peak demand is 200,000 lbs per hour and the projected average demand is 120,000 lbs per hour. Sufficient redundancy, therefore, exists to remove a boiler from service for retrofit or one-for-one replacement; however, scheduling must be adhered to in order to avoid peak periods of demand which can be met only at full capacity. If 100,000 lb per hour boilers are substituted for the existing equipment, as will be recommended, the conversion of the third boiler should not be concurrent with peak demand.

2.2 Retrofit of Existing Plant

We next consider the possibility of retrofitting the existing plant as a less costly alternative to replacement. In the general case such retrofit would include a complete new installation of coal handling and storage equipment and facilities, as well as the actual modifications to the boilers. In general, the retrofit would include:

- installation of spreader stoker and grate equipment, generally involving the removal of the oil burners to accommodate this equipment;
- addition of ductwork and fans to provide sufficient air to the area beneath the coal grate;
- modification to combustion control systems;
- ash collection and reinjection systems;

- emissions control systems, which may include cyclone collectors, electrostatic precipitators or fabric filters and flue gas desulfurization equipment;

- ash and chemical storage space and loading facilities.

The new coal handling equipment, which would be required for either retrofit or replacement includes:

- coal receiving and unloading facilities;
- conveyor systems;
- scales, hoppers and chutes;
- storage facilities;
- coal spreader with feeder assembly;
- leachate control and treatment facilities.

In considering gasification of coal, new handling equipment similar to that needed for direct firing would have to be installed. In addition to boiler modification, a gasification plant would be required.

A typical gasification plant would include the following basic systems:

- coal pretreater (not required in some systems with certain types of coal);
- gasifier;
- steam supply (source steam, waste product boiler or integral system);
- air supply (for low-Btu gas);
- oxygen supply (for medium and high-Btu gas);
- slag and char removal, handling and storage;
- gas stream clean-up (which includes some or all of the following equipment: cyclone

collectors, scrubbers, electrostatic precipitators, desulfurization system, oil, tar and sulfur storage);

- shift converter (high-Btu gas);
- methanator (high-Btu gas);
- gas distribution system.

Requirements for systems and equipment vary with the specific process, type of coal to be used and end use of the gas product. For example, coal pretreatment is not required for many non-caking coals and certain gasifiers; gas stream clean-up requirements may not include desulfurization if low sulfur coal is used, and particulate removal requirements vary with end use.

Boiler modification from oil to gas firing is relatively simple for high-Btu gas and somewhat more difficult for low and medium-Btu gas, in the general case, because tolerances for efficient combustion are narrow. The burner and combustion controls must be replaced or, at least, revamped.

Low-Btu gas is relatively inefficient when combusted directly because of low flame temperature and finds better application in industrial processes, although it has been successfully used for heating on a demonstration basis. Low-Btu gas is well suited for use in gas turbines, but an extremely clean gas stream is needed to prevent particulate buildup and turbine blade damage. Medium-Btu gas is manufactured by processes similar to low-Btu gas, with oxygen substituted for air. This process is more efficient than the low-Btu process, but requires the construction and operation of an oxygen plant. Both types of gases are processed through gasifiers which are becoming increasingly commercially available in small enough sizes to allow multi-train modular installation for the typical demand at Picatinny. High-Btu

gas is processed on a much greater scale than the low and medium-Btu gases and cannot be efficiently produced at a scale to match the demand level under consideration.

In addition to the retrofit and new equipment necessary to use gasified coal, provisions must be made to collect and store by-products, both saleable and waste, that result from these processes. Since storage of sufficient quantities of gas to satisfy demand in the event of outages is impractical, alternative fuels must be provided.

The Picatinny Arsenal Power Plant was formerly coal-fired, but none of the equipment needed for reconversion to coal-firing or handling coal for gasification is currently in place. The railroad tracks, necessary for transportation, appear to be in operational condition. All other facilities, from unloading outward, must be constructed.

The retrofitting of the boilers has been discussed in a general sense. Now consider the specific boilers in place at Picatinny. The two major boilers are 160,000 lb per hour oil/gas-fired, built in 1943. These units were originally designed to fire pulverized coal. The third boiler is a 50,000 lb per hour oil-fired package unit, built in 1971. Reconversion of the two larger units is not considered cost effective. The newer unit can not be retrofitted for coal firing due to tube configuration and space requirements for this package unit.

2.3 Replacement of Existing Equipment

Preliminary boiler sizing indicates that three boilers rated at 100,000 lb per hour each would meet the range of steam demands efficiently, with flexibility to provide steam requirements using one or two units, reserving the third for standby. Replacing the existing equipment

with 100,000 lb per hour boilers on a one-for-one basis is possible, but only if rigid scheduling is adhered to, since sufficent redundancy to meet peak demands will not exist at all times during the conversion process. In addition, major modifications would be required to the building enclosure to allow for the new boilers and to bring the existing structure up to uniform standards. The extensive modifications that are required are not considered cost effective when compared to investing in a new building.

2.4 Site Constraints at the Existing Plant

With a direct-firing option, a new boiler plant would be required. If gasification was considered, a retrofit could be designed for the existing plant and a new process plant built. Prime consideration should be given to sites adjacent to or in the immediate vicinity of the existing plant for the new boiler plant or a gasification process plant.

The most important site requirements for direct firing or gasification of coal include accessibility by rail; sufficient area for storage of coal, ash and by-products, if any; and environmental considerations. The railroad track is in place and appears to be in operational condition, satisfying accessibility criteria.

Good practice demands that a thirty day supply of coal be stored on-site, and that sufficient space be allocated for storage of a ten day production of ash and by-products from the gasification process. In addition, the plant should have the capability of burning fuel oil, on a standby basis, to assure reliability. Thus, fuel oil storage is also required.

Picatinny Arsenal fired coal previously. The site of the original coal pile would be favored as the storage location were coal firing reinstated. This site does not interfere with the existing oil tanks, allows them to be used for standby and takes advantage of the rails and switchgear already in place. The site is sufficiently close to the existing plant to minimize new piping.

2.5 Summary of Option Selection

Figure 2-1 is a summary of the above discussion. It compares, on a simplified "yes-no-maybe" basis, the various coal-use options against the major factors used in the evaluation. Displayed graphically is the difficulty in retrofit or replacement of existing boilers because of lack of redundancy, the marginal capability of the plant to accept new units and the availability of adjacent land. Naturally, not all of these factors are equally weighted. As discussed, the output of high-Btu gas or synthetic liquid fuel oil is inherently inefficient with respect to demand, a fact sufficient to eliminate consideration of these processes. The three remaining -- direct firing of coal, low-Btu and medium-Btu gasified coal -- are each considered viable processes to be further explored for the Picatinny Arsenal.

EVALUATIVE FACTORS FOR COAL CONVERSION PROCESSES

PICATINNY ARSENAL

EVALUATIVE FACTORS \ COAL CONVERSION PROCESSES	DIRECT COAL FIRING	LOW-BTU GASIFICATION	MEDIUM-BTU GASIFICATION	HIGH-BTU GASIFICATION	LIQUEFACTION
PROCESS EFFICIENCY FOR DEMAND	●	●	●	◒	○
EXIST. EQUIPMENT REDUNDANCY AT PLANT	◒	◒	◒	◒	◒
RETROFIT POSSIBILITY OF EXISTING PLANT	◒	◒	◒	●	●
SUFFICIENCY OF EXISTING PLANT AREA	◒	◒	◒	◒	◒
SUFFICIENCY OF EXISTING SITE AREA	●	●	●	●	●

LEGEND:

● POSITIVE RELATIONSHIP

◒ INTERMEDIATE RELATIONSHIP

○ NEGATIVE RELATIONSHIP

FIGURE 2-1

3.0 APPLICATION TO PICATINNY ARSENAL

The viable options for converting from fuel oil to coal at the Picatinny Arsenal are direct firing of coal or gasification into low-Btu or medium-Btu gas. Either process can be implemented adjacent to the existing power plant.

3.1 Environmental Considerations

Environmental regulations exist covering source fuel and emissions for air pollution and discharge components and temperature for water pollution. These regulations, promulgated by all levels of government, have been considered in our analysis of the various systems. Table 3-1 summarizes the applicable air pollution standards for coal-fired boilers. No standards for the gasification plant exist at this time. If standards were promulgated, we feel they would be similar to 40CFR60, Subpart J, Section 60.100 of the Primary National Air Standards, which we have considered in this report. Should regulations be developed which are substantially different than anticipated, impact on cost could result.

3.2 Storage Considerations

Production of steam or gas requires that coal be received and stored at the Plant site. Railroad trackage is available, which includes a siding. A trackhouse, thaw-pits and unloading facilities are required. The trackhouse for unloading is provided to protect against escape of fugitive dust during off-loading. The coal should be stored in the vicinity of both the trackhouse and plant.

A variety of coal storage techniques are available. In order of increasing costs, these are:

- open pile
- uncovered, walled enclosure
- silos
- reclaim building

TABLE 3-1

SUMMARY OF APPLICABLE AIR POLLUTION STANDARDS FOR COAL FIRED BOILERS

A. Emissions

Smoke[1]	No visible smoke permitted
Particulates	16.5 pounds per hour
Sulfur Dioxide[2]	0.3 lb/10^6 Btu heat input

B. Sulfur Content of Compliance Fuel: 0.2%

C. Clean Air Act Permitted Increments to Ground Level Concentrations of Existing Air Quality[3]

Sulfur Dioxide	
Annual	20 $\mu g/m^3$
20-Hour	91 $\mu g/m^3$
3-Hour	512 $\mu g/m^3$
Particulate	
Annual	19 $\mu g/m^3$
24-Hour	37 $\mu g/m^3$

---

1. Exclusive of water vapor.
2. Heat input is the sum of all boiler inputs discharging through a single stack.
3. May not be applicable according to newly proposed rules.

Although coal was stored in the open when Picatinny originally fired coal, in light of present environmental considerations, open storage must be considered unacceptable. A walled enclosure 105 feet by 360 feet truncated to conform to the railroad tracks would be required for a 30-day supply of coal. A bottom liner will control the leachate and enable collection and neutralization prior to discharge. The third and fourth methods, while providing for completely covered storage, need only be employed when the facility must meet stringent environmental regulations, when weather conditions require enclosed storage or when space considerations govern. Such is not the case at Picatinny, and the walled enclosure is selected as a basis of this study. A layout of the storage is shown in Figure 3-1.

From an unloading pit, coal will be lifted onto a stocking out conveyor. The discharge will be fitted with a dust preventive spout. Loadout system will be sized at 100 tons per hour to move railroad cars rapidly through the system. Coal will be reclaimed from the pile by a wheeled front-end loader. The loader will act to compact the coal pile and to control the inventory on a first-in-first-out basis. Coal will be moved into power plant bunker storage at the rate of 42 tons per hour, four times the maximum burning rate. This will permit idle time for preventive maintenance and allow the bunkers to be filled in one shift per day. For synthetic fuel production the infeed rate will be selected as required by the process, and will probably be in the range of 50 tons per hour. Synthetic fuel, because of inefficiencies inherent in the processes, will require a greater volume of coal storage than required for direct firing.

Storage is sized to provide thirty days emergency supply at peak load. According to the data in Table 1-1, this will amount to 7200 tons for direct firing and 9200 tons for gasification. Fuel oil will remain as a standby fuel.

COAL STORAGE

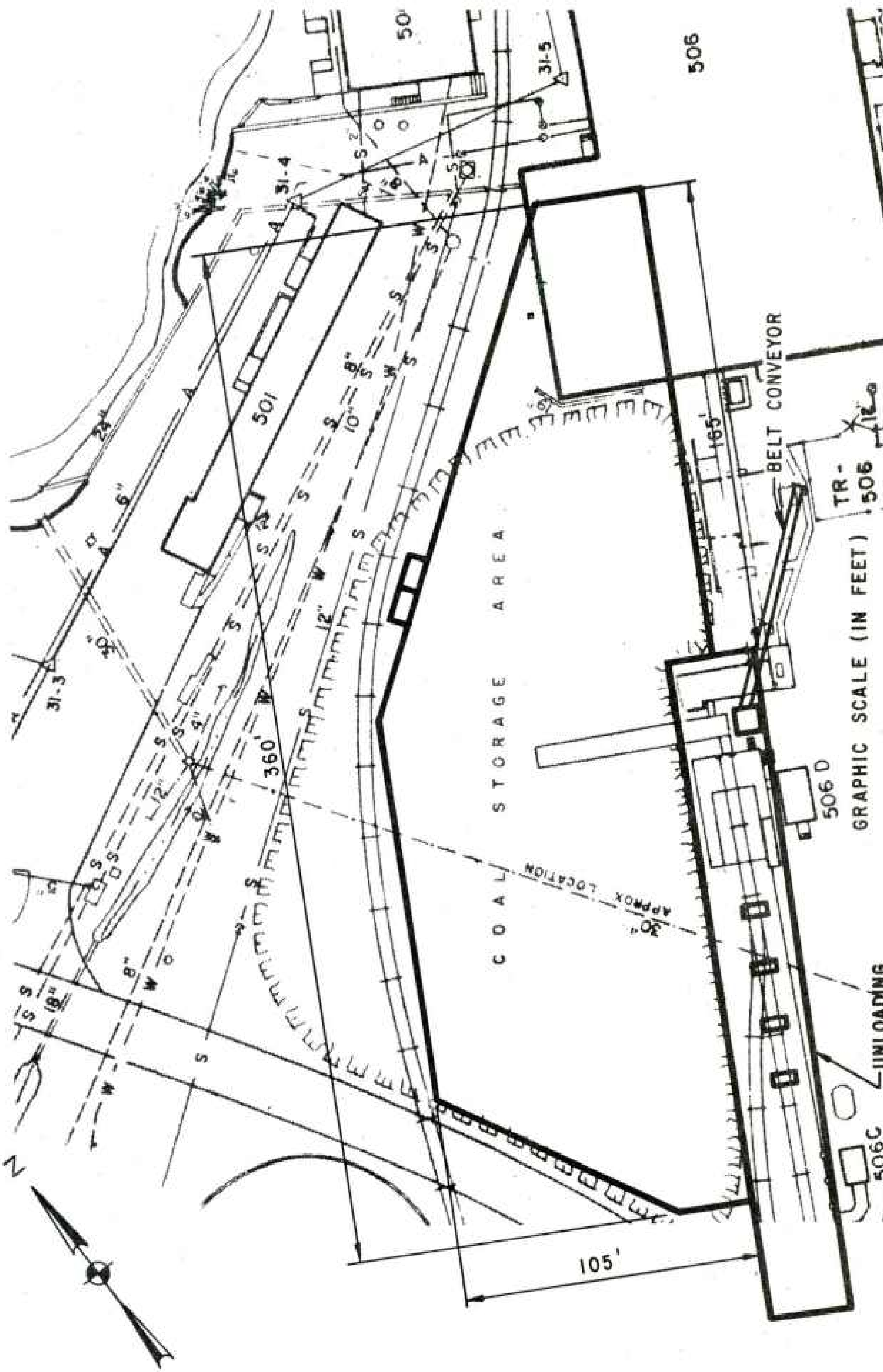


FIGURE 3-1

Coal will be elevated on a belt conveyor into the plant bunker area. The bunkers will be fed by a tripper conveyor to spread coal for use by each boiler. The shape of the bunker bottom will depend on the method of firing the fuel. Interposed between the pile and the bunkers will be a crusher to prevent large sized material from passing into the system. The crusher will be protected by an electro-magnet to remove tramp iron. Other large uncrushables may be removed after inspection at a check screen. Only one day of in-plant storage is anticipated, with an underbunker conveyor system needed to assure flow to the boiler being fired.

Existing fuel oil lines will be extended to meet the needs of the new plant site. A transfer pumping station will be installed along side of the coal conveyor with lines supported on conveyor gallery supporting steel. A day tank will be installed in the new plant to avoid return to the main storage tank.

3.3 Boiler Types and Related Environmental Control Equipment

Direct-firing of coal can be accomplished using stoker boilers, pulverized coal boilers or fluidized bed combustion units. Recalling that satisfying demand with flexibility, efficiency and back-up requires three boilers sized at 100,000 pounds per hour, we review the boiler types with respect to this capacity rating. Pulverized coal units are inefficient in the size range of interest here; in addition maintenance costs are high. Therefore, pulverized coal boilers are not considered for this installation. Both stoker and fluidized bed boilers are suitable for this application. Both types of boilers are proven technology with stokers having been used continuously for many years. While fluidized bed technology is rooted in the past, development for coal combustion had not been refined until the need

for pollution control was imposed. After several years of development, commercial units are available and competitive, both economically and reliably, with stoker boilers.

The stoker boiler discharges fly ash in excess of permissible emissions and, therefore, requires environmental control. A shortage of low sulfur coal should be anticipated, at least at competitive prices, and SO_2 removal should also be provided. Separate systems for filtration of fly ash and removal of sulfur are available, but the use of separate systems is generally found to be economical only at utility-size scale. The equipment size proposed at Picatinny indicates that a system combining both fly ash and sulfur removal would be suitable. The selection of specific flue gas desulfurization equipment should be made during the preliminary design phase of the project and a decision made then whether to use a wet or dry system.

The wet system includes a mixing chamber, usually a venturi nozzle that permits intimate contact between the gas and a liquid bath, and combination contact tower (scrubber) and liquid removal chamber. Particulate matter is carried along with the gas stream, making contact with the chemically treated liquid, and is captured with the chemical reaction precipitates formed in capture of the SO_2 gas. The dry system includes a spray chamber in which flue gas is sprayed with an SO_2 sorbent. Particles, and the result of the chemical reaction between SO_2 and the sorbent, are then trapped on filter media in a baghouse. An induced draft fan is installed downstream of the baghouse, and thus "sees" clean air at a temperature of approximately 150°F.

Both the wet and dry methods require that flue gas be reheated after treatment. Heat is added to permit the gas to form an acceptable plume. On a cold, dry day the moist air would

rapidly condense and fall as rain in the immediate area. In extreme cold, ice crystals would form. Heat can be taken from the boiler in the form of a steam coil in the discharge of the stack, or can be taken from the flue gas. Precise measurement of particulate matter and SO_2 concentration downstream of the process would dictate the quantities of untreated gas that could be added.

A typical stoker/scrubber facility configuration is shown in Figure 3-2.

A fluidized bed boiler requires no flue gas desulfurization process, and thus has an advantage over stoker boilers. Another advantage is size, being smaller than a stoker, a fluidized bed unit when part of a multiple train, will have a considerably smaller building envelope.

The fluidized bed boiler uses limestone in the bed to act as a sorbent for sulfur in the coal. The waste product is a dry powder compared to the 50% wet sludge flue gas desulfurized product. All fly ash produced is collected without further processing. The product can be used to alkalize sewage sludge, as a soil conditioner and as a pozzolith. The material rejected from the bed is a mixture of impurities which varies with the coal. It is a sand-like, alkaline powder, mostly calcium sulfate. It may be used as landfill without additional treatment.

Fly ash from the fluidized bed may be collected in a baghouse, permitting the operation to be performed in the dry state. The problems associated with electrostatic collectors are thus avoided. While some operating difficulties exist with baghouses their technology is a known factor, whereas electrostatic collectors are more subject to the vagaries of dust chemistry and temperature.

TYPICAL STOKER FIRED BOILER PLANT WITH FLUE GAS DESULFURIZATION

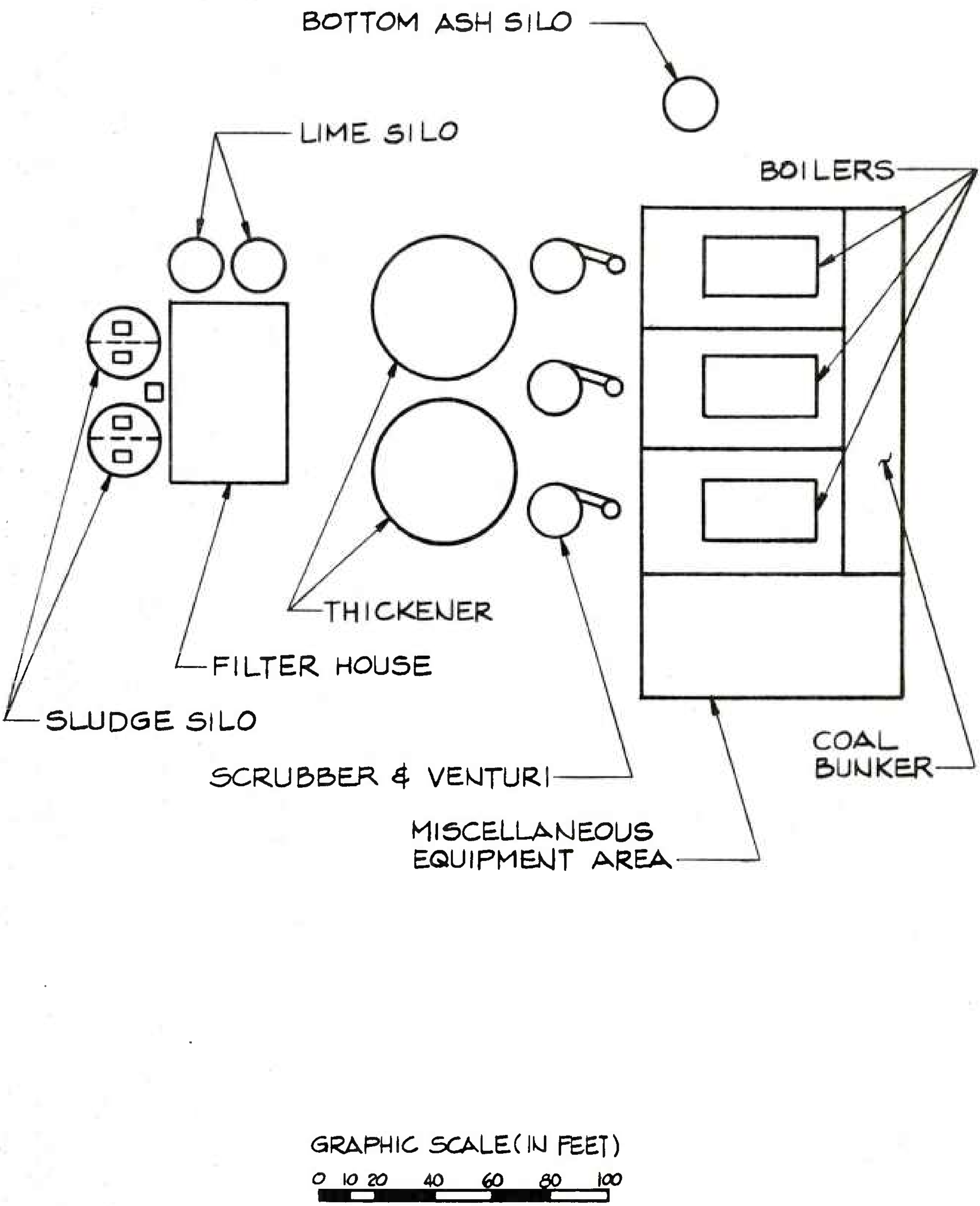


FIGURE 3-2

Both the bed material and fly ash rejection products of fluid bed combustion may be stored in silos until ready for final disposal. Fluidized bed combustion reject products are easier to handle, store and dispose of than those of stoker boilers with flue gas disulfurization, which requires lugger pans to haul sludge to sealed landfills. The products of fluidized bed combustion are generally removed in bulk material transport trucks, in the same manner that limestone is delivered.

A typical fludiized bed combustion boiler facility configuration is shown in Figure 3-3.

3.4 Gasification Systems

Gasification of coal can be accomplished in fixed, entrained or fluidized bed gasifiers. The product gas is then processed to remove deleterious material. With some systems, reject material such as sulfur can be reclaimed as a by-product of value. The demand for gas at Picatinny Arsenal would require approximately 250 tons of coal per day to be processed. In this capacity range and with consideration of desirability of a multi-train plant to allow partial operation in the event of breakdown and flexibility to match demand, five small fixed-bed gasifiers would be recommended. Four units are required to meet peak demand and the fifth unit is provided to assure reliable, continued operation in the event that one unit is removed from service.

During the preliminary design phase, a decision must be made concerning the selection of a single or two-stage gasifier. Both types of units are commercially available and can produce a range of product gases. The two-stage gasifier permits gas to be taken from both upper and lower chambers. In the upper stage the temperature is lower, reducing the amounts of tar and oils carried in the gas stream. This

TYPICAL FLUIDIZED BED BOILER PLANT WITH BAGHOUSE

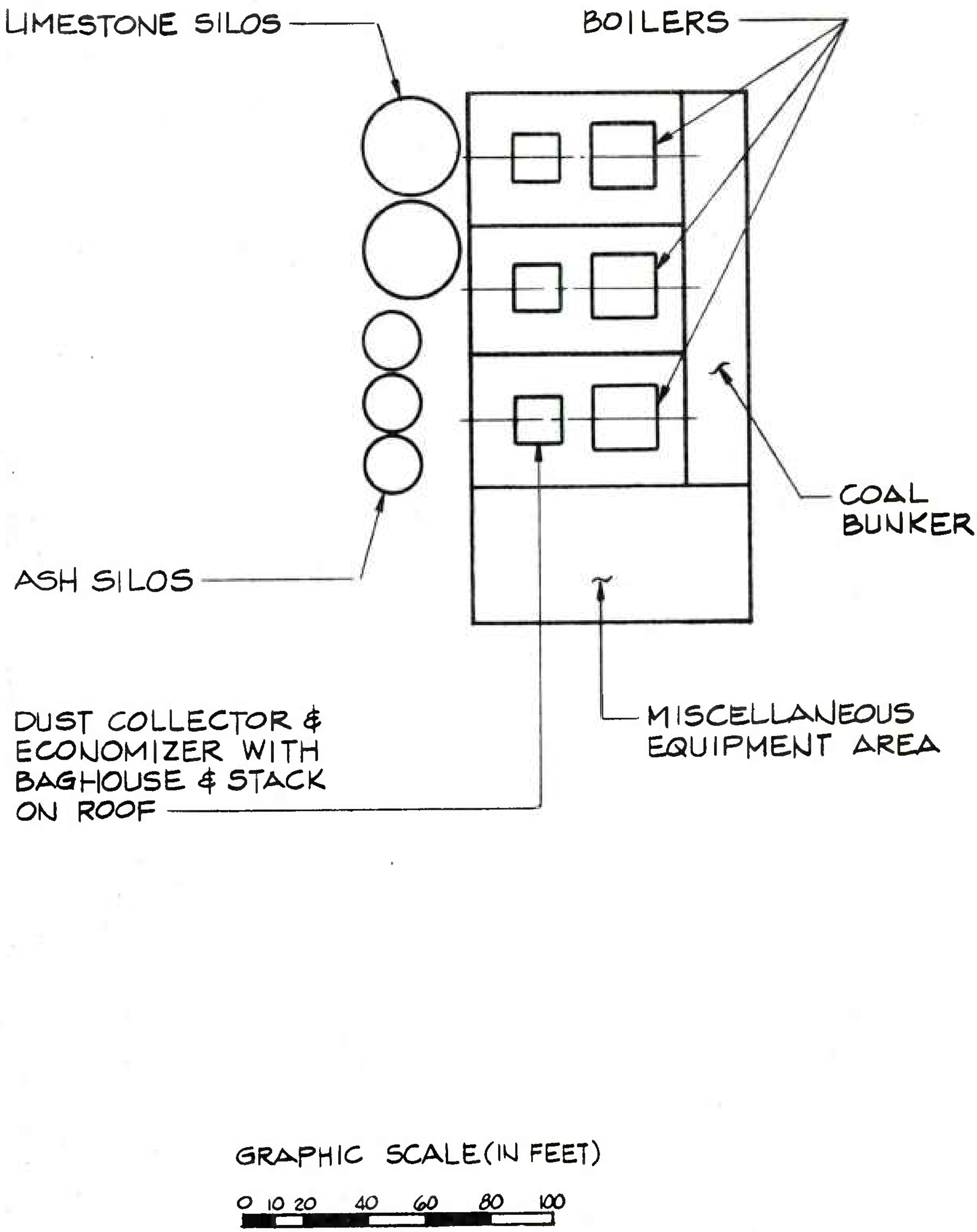


FIGURE 3-3

minimizes the deposits in piping systems and equipment and reduces the overall clean-up required. Two-stage gasifiers are not, however, produced with mechanical stirrers and therefore cannot handle strongly caking coal. The single-stage gasifier will accept all types of coal without need for pretreatment. Thus the process selected is heavily dependent on the source of fuel.

The gasification process is simple. Coal is fed into a gasifier and is dried, heated and combusted as it migrates through various zones down toward the grate, where it is removed as ash. The gas from combustion rises and is the vehicle which treates the incoming coal. Either air or oxygen is introduced below the grate. If air is used the product is a low-Btu gas, with a high heating value of 100 to 150 Btu/scf. When oxygen replaces air the product is medium-Btu gas, with a high heating value of 250 to 350 Btu/scf. If medium-Btu gas is to be produced, the cost of constructing and operating an oxygen plant must be considered. The product gas also requires clean-up prior to firing.

The clean-up process includes particulate, tar and sulfur removal as well as cooling of the gas. Clean-up systems vary with system design and manufacturer, and include some or all of the following equipment: cyclones, quenchers, coolers, tar separators, condensers, cooling towers, electrostatic precipitators and desulfurization systems.

By-products vary with both the system and the type of coal, but generally include ash, tar, oil and sulfur. Some of these by-products, such as sulfur when produced in elemental form, are saleable. Tars produced may be useable in boilers to produce steam required in the gasification process. All by-products must be stored and transported to final disposition.

There is an additional consideration which must be mentioned here. The existing boilers, while convertible to the required gas firing, are quite old. Indeed it would probably be prudent to replace them in several more years, in any case. For this preliminary assessment and comparison of primary coal systems, we do not investigate the economic consequences of doing so. It should be kept in mind if the gasifier option is selected for implementation.

A typical gasification configuration is shown in Figure 3-4.

3.5 Operating Considerations

Concern for following load exists with both gas and steam production. A stoker fired or fluidized bed boiler can act efficiently at one-third rated capacity. Therefore, a boiler plant with three 100,000 lb per hour boilers can operate over a range of 33,000 to 300,000 lbs per hour. A gasifier, of the type under consideration, would have a turndown ratio equivalent to that of the coal-fired unit and, therefore, the two systems are comparable on this basis.

In the event of interruption of coal supply, for either direct-firing or gasification, fuel oil must be kept in reserve. If a new boiler plant is constructed for direct-firing of coal, the boilers would have coal and oil-firing capability. With the gasification option, the retrofitted boilers should be equipped with burners capable of firing gas and oil.

3.6 Turbine Generators

The existing power generation plant includes two turbine-generators at 3000 kW output each. These operate in a condensing mode with two levels of extraction pressures. Condensing generation places the plant at an energy disadvantage since it cannot operate at the economy level inherent

TYPICAL LOW-BTU GASIFIER PROCESS PLANT

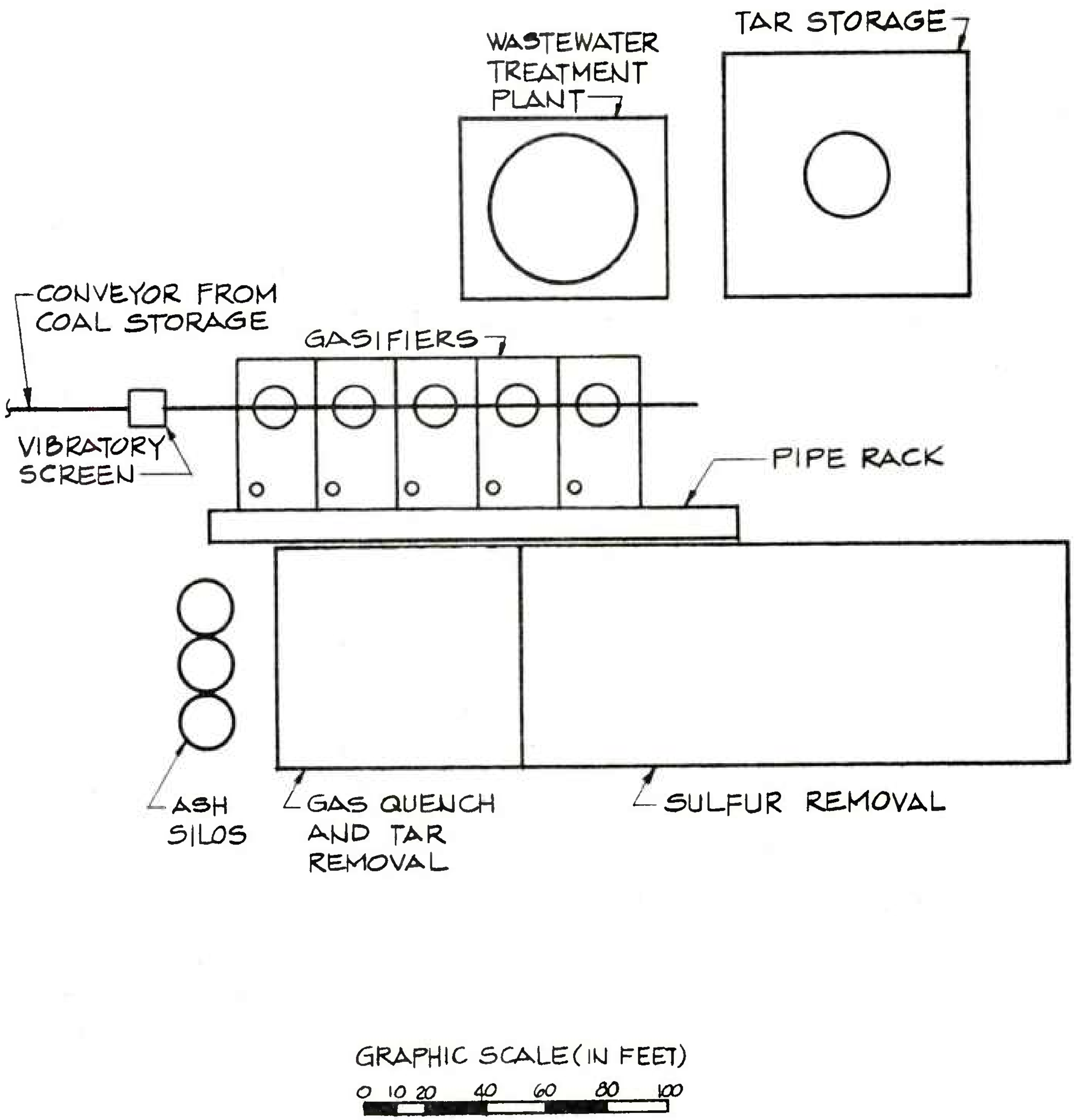


FIGURE 3-4

in utility stations. However, operation in a back pressure or strict cogeneration mode, that is, permitting steam to expand through a turbine from a high pressure to the final distribution pressure, offers economy at only a small increase in capital and operating costs. Thus we recommend adoption of this mode of operation. In addition, if boilers are selected at typical industry performance levels of 600 psig and 700°F discharge, each 100,000 lb/hr of steam could produce approximately 4000 kW of electricity. This would improve the economics of the station to generate electricity and reduce electric purchase. If the higher pressure boiler is selected, the turbines would be replaced by units capable of accepting the higher pressure inlet steam. This decision is an economic one, and preliminary evaluation indicates a slight benefit with new turbines as opposed to retaining the existing units. Engineering judgement favors new equipment for reasons of reliability. Therefore, we recommend new turbines for direct firing and retaining the existing turbines with gasification.

Note that in the recommended mode of operation, where all steam discharging to the export steam and boiler plant auxiliaries passes through the turbine, electric generation follows the steam demand. It is not possible to run independently of the utility but the system must be grid connected at all times.

The new turbines will be single extraction type operating against a back pressure of 60 psig. An uncontrolled extraction point at 125 psig will provide steam for some process use and for high pressure heaters in the boiler feedwater circuit. The need for distribution of 125 psig steam has been diminishing as the character of the Arsenal changes. It may become more cost effective in the future to install small electric boilers at remote areas than to suffer the energy loss

required in maintaining a low usage high pressure piping system. The turbine back pressure of 60 psig will suffice for heating requirements throughout the distribution system. Note that if all the 125 psig steam distribution were eliminated, no significant change would be required for turbine operation.

With a gasification process, the present boilers would be modified for gas firing and the existing turbine-generators would be retained. A new power plant would be built and the turbine-generators moved from their present location to the new plant. The boiler steam pressure level must be matched to the existing installation. However, to operate in the cogeneration mode would then require turbine modification to remove the last stages of blading and have the exhaust port closed, except for drainage. This would also reduce the ability to generate at the present rating. The installation would be staged to permit continued operation of at least one turbine-generator for facility power reliability.

3.7 Summary

Three processes are considered viable for further investigation:

- Stoker boilers with FGD
- Fluidized bed boilers with baghouses
- Low-Btu gasification of coal

Medium-Btu gasification has been excluded because capital and operating costs associated with the required oxygen plant would penalize this process with respect to the demand at Picatinny Arsenal. Site plans for the three options are shown in Figures 3-5, 3-6 and 3-7.

SCHEMATIC DIAGRAM OF STOKER-FIRED BOILER WITH FLUE GAS DESULFURIZATION

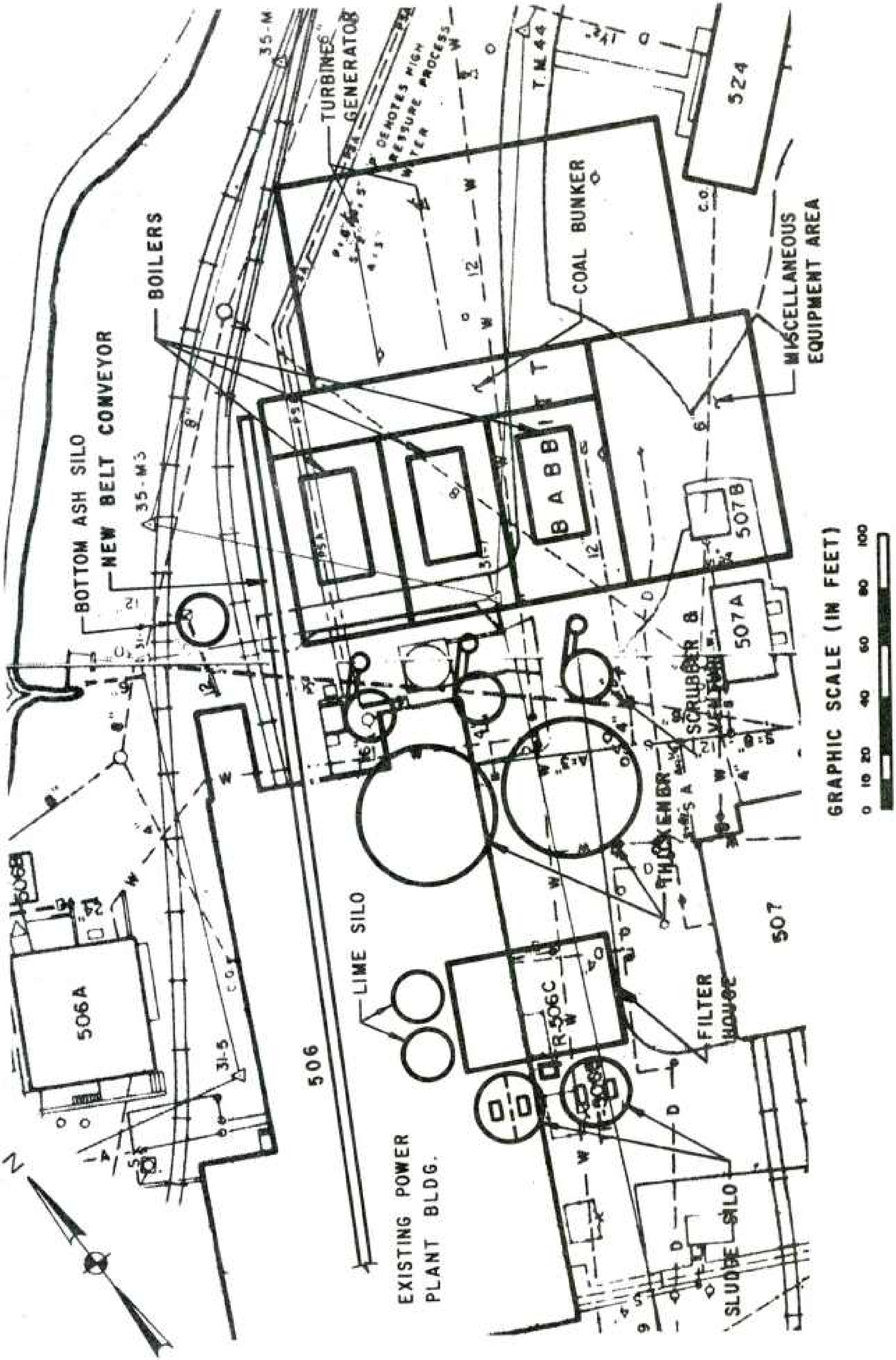


FIGURE 3-5

SCHEMATIC DIAGRAM OF FLUIDIZED BED BOILER WITH BAGHOUSE

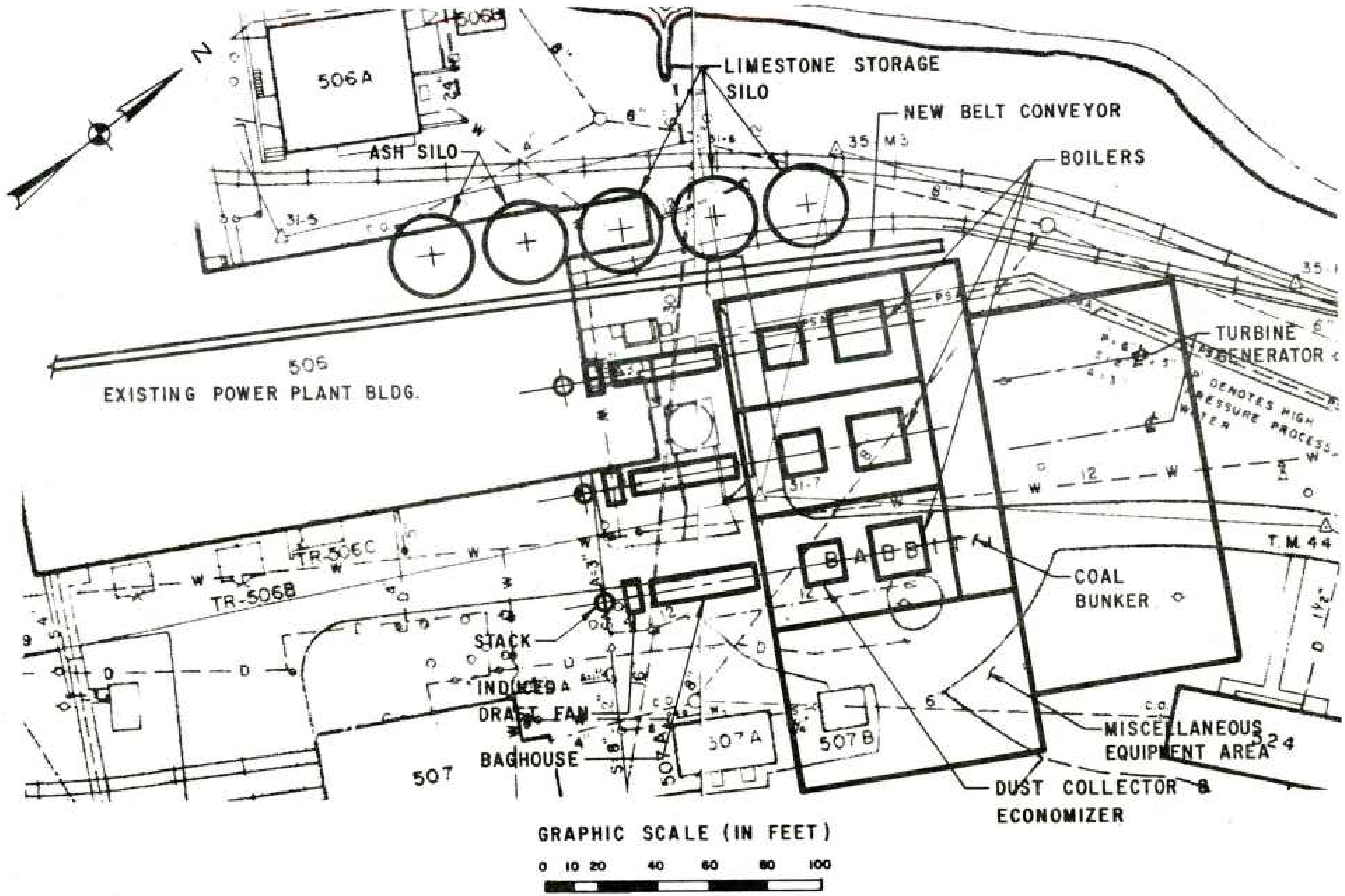


FIGURE 3-6

LOW-BTU GASIFICATION PROCESS PLANT

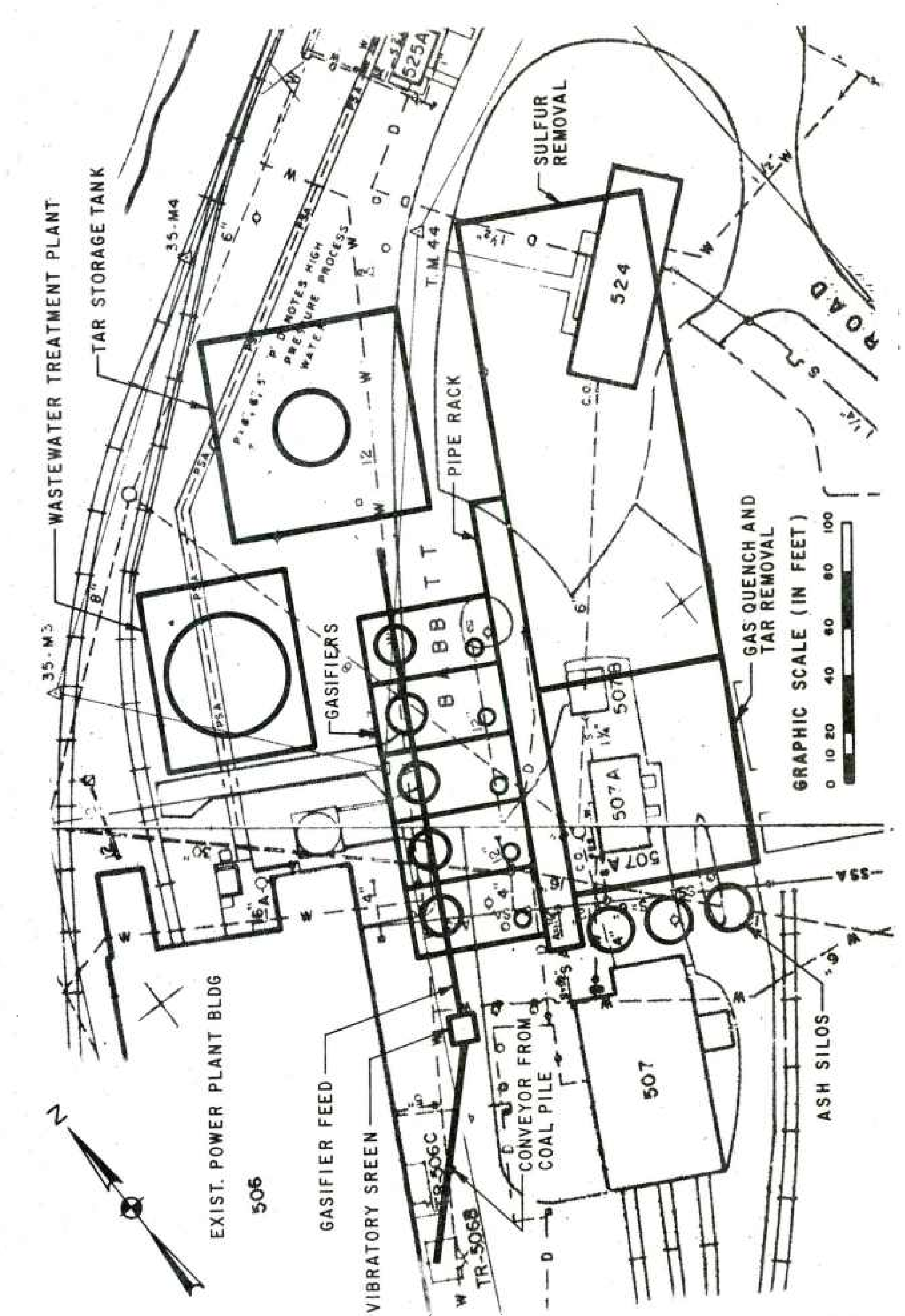


FIGURE 3-7

4.0 ECONOMIC ANALYSES AND RECOMMENDATIONS

The cost analysis presented here was derived on the basis of direct quotation, communications with suppliers and the current literature describing the various systems. The economics are based on the conceptual design and engineering information prepared for each option.

4.1 Cost Analysis

The materials, supplies and labor for plant operation and maintenance were estimated to reflect current practices. Information from previous work was used to prepare both the capital and operating cost estimates for this study. It is useful to set out some of the basic information used here:

- Labor costs are taken at $25,000 annually per individual.
- Repair materials estimated at 2% of capital costs (before application of SIOH).
- Electric costs at $0.05/kWh.
- Lime costs at $15/ton.
- Limestone costs at $15/ton.
- Sludge disposal costs at $30/ton.
- Ash and FBC waste disposal costs at $15/ton.
- Coal costs estimated to be $50/ton delivered.
- Current oil costs taken to be $0.80/gallon.
- By-products from gasification process assumed to have value equal to disposal cost.

- Capital costs include contractor's overhead at 15%, contractor's profit at 10%; general contractors overrides for overhead and profit at 5% and 5%.

- Contingency estimated at 10% for the coal fired options and 15% for gasification, contingency applied before SIOH. The larger contingency for the gasification option is justified because of the uncertainties inherent in the new technology.

The three options that have been found most promising for specific application at Picatinny Arsenal are:

- Option I - Installation of a stoker boiler power plant, which would include flue gas desulfurization and new turbine generators.

- Option II - Installation of a fluid bed combustion boiler power plant and new turbine generators.

- Option III - Installation of a multi-train gasification plant producing low-Btu gas. Exisitng boilers would be modified to fire gas and existing turbines would undergo retrofit eliminating condensing generation. Boilers and turbines would be relocated to a new structure in the vicinity of the existing plant.

All options include capability for oil firing on a standby basis to assure continued operation in the event of coal delivery difficulties.

Capital and operating costs for each option have been tabulated and are provided according to the following:

Option	Capital Costs	Operating Costs
I	Table 4-1	Table 4-2
II	Table 4-3	Table 4-4
III	Table 4-5	Table 4-6

Inspection of these results yields some useful information:

- No significant difference in capital costs for coal handling and delivery exists among the options.

- The new boilers for Options I and II and the process plant in Option III each represent approximately the same investment amount. The boiler costs are roughly half the total costs for Options I and II, but the process plant and boiler modifications in Option III represents almost two-thirds of the cost of that option.

- Pollution control is a significant fraction of the cost of the stoker boiler system, Option I.

- Significant differences exist among the three options in capital costs: Option I costs 42% more than Option II and Option II costs 29% more than Option III.

TABLE 4-1

SUMMARY OF CAPITAL COSTS[1]

OPTION I: STOKER BOILERS, FLUE GAS DESULFURIZATION, NEW TURBINE GENERATORS

Line Item	Total	Percent of Grand Total	Unit Cost[2] ($/lb)
1. Coal Delivery and Handling			
Railcar Unloading Building	820	2.0	2.73
Coal Preparation Building	158	0.4	0.53
Coal Storage Pile	965	2.4	3.21
2. Boiler Plant			
In-Plant Coal Handling	756	1.9	2.52
Boilers	18,964	47.1	63.21
3. Pollution Control			
Scrubber System	6,239	15.5	20.80
Lime and Sludge Storage	802	2.0	2.67
Ash Handling	297	0.7	0.99
4. Turbines	4,201	10.4	14.00
5. Yardwork, Utilities, Demolition and Miscellaneous	1,531	3.8	5.10
Subtotal	34,733	86.2	115.77
Contingency at 10%	3,473	8.6	11.58
Total Capital Cost	38,206	94.8	127.35
SIOH at 5.5%	2,102	5.2	7.00
GRAND TOTAL	40,308	100.0	134.35

1. All dollars in 1000's, costs estimated as of 3rd Quarter 1979.
2. Capital unit costs based on 300,000 lb/hr installed boiler capacity.

TABLE 4-2

SUMMARY OF OPERATING COSTS[1]

OPTION I: STOKER BOILERS, FLUE GAS DESULFURIZATION, NEW TURBINE GENERATORS

Item[2]	Total	Percent of Grand Total	Unit Cost[3] ($/10^{6}Btu)
1. Labor (15 added)	1,625	26.8	1.21
2. Materials	1,127	18.6	0.85
3. Disposals	1,024	16.9	0.78
4. Electric:			
System Operation	175	2.9	0.13
Cogeneration (Savings)	(641)	(10.6)	(0.49)
5. Coal	2,750	45.4	2.08
GRAND TOTAL	6,060	100.0	4.57

1. All dollars in 1000's, estimated at 3rd Quarter 1979.
2. Line Items 1, 2, 3 and 4 are incremental and relative to current oil operations.
3. Unit operating costs based on projected annual demand of 1.32 x 10^{12} Btu/yr.

TABLE 4-3

SUMMARY OF CAPITAL COSTS[1]

OPTION II: FLUIDIZED BED COMBUSTION BOILERS, BAGHOUSES, NEW TURBINE GENERATORS

Line Item	Total	Percent of Grand Total	Unit Cost[2] ($/lb)
1. Coal Delivery and Handling			
Railcar Unloading Building	820	2.2	2.73
Coal Preparation Building	158	0.4	0.53
Coal Storage Pile	965	2.6	3.21
2. Boiler Plant			
In-Plant Coal Handling	754	2.1	2.52
Boilers	18,205	49.8	60.68
3. Pollution Control			
Baghouse	2,598	7.1	8.66
Limestone Storage	1,328	3.6	4.43
Ash Handling	924	2.5	3.08
4. Turbines	4,201	11.5	14.00
5. Yardwork, Utilities, Demolition and Miscellaneous	1,531	4.2	5.10
Subtotal	31,484	86.2	104.93
Contingency at 15%	3,148	8.6	10.49
Total Capital Cost	34,632	94.8	115.44
SIOH at 5.5%	1,905	5.2	6.35
GRAND TOTAL	36,537	100.0	121.79

1. All dollars in 1000's, costs estimated as of 3rd Quarter 1979.
2. Capital unit costs based on 300,000 lb/hr installed boiler capacity.

TABLE 4-4

SUMMARY OF OPERATING COSTS[1]

OPTION II: FLUIDIZED BED COMBUSTION BOILERS, BAGHOUSES NEW TURBINE GENERATORS

Item[2]	Total	Percent of Grand Total	Unit Cost[3] ($/10^{6}Btu)
1. Labor (14 added)	1,600	28.5	1.28
2. Materials	1,069	19.0	0.81
3. Disposals	331	5.9	0.25
4. Electric:			
System Operation	514	9.1	0.39
Cogeneration (Savings)	(641)	(11.4)	(0.49)
5. Coal	2,750	48.9	2.08
GRAND TOTAL	5,623	100.0	4.32

---

1. All dollars in 1000's, estimated at 3rd Quarter 1979.
2. Line Items 1, 2, 3 and 4 are incremental and relative to current oil operations.
3. Unit operating costs based on projected annual demand of 1.32 x 10^{12} Btu/yr.

TABLE 4-5

SUMMARY OF CAPITAL COSTS[1]

OPTION III: GASIFICATION PLANT, BOILER RETROFIT, EXISTING TURBINE GENERATORS

Line Item	Total	Percent of Grand Total	Unit Cost[2] ($/lb)
1. Coal Delivery and Handling			
Railcar Unloading Building	820	2.9	3.15
Coal Preparation Building	158	0.5	0.63
Coal Storage Pile	1,379	4.8	5.08
2. Process and Boiler Plant			
Process Plant	17,381	61.1	69.43
Boiler Conversion	759	2.7	3.03
3. Pollution Control			
Ash Silos	138	0.5	0.54
4. Turbine Modifications	1,088	3.8	4.35
5. Yardwork, Utilities, Demolition and Miscellaneous	1,633	5.7	6.47
Subtotal	23,356	82.4	92.68
Contingency at 15%	3,503	12.4	13.90
Total Capital Cost	26,859	94.8	106.58
SIOH at 5.5%	1,477	5.2	5.86
GRAND TOTAL	28,336	100.0	112.44

1. All dollars in 1000's, costs estimated as of 3rd Quarter 1979.
2. Capital unit costs based on current 252,000 lb/hr system capacity.

TABLE 4-6

SUMMARY OF OPERATING COSTS[1]

OPTION III: GASIFICATION PLANT, BOILER RETROFIT, EXISTING TURBINE GENERATORS

Item[2]	Total	Percent of Grand Total	Unit Cost[3] ($/$10^6$Btu)
1. Labor (25 added)	1,875	27.6	1.42
2. Materials	566	8.3	0.43
3. Disposals	272	4.0	0.21
4. Electric:			
System Operation	160	2.4	0.12
5. Coal	3,929	57.8	2.98
GRAND TOTAL	6,802		5.16

1. All dollars in 1000's, estimated at 3rd Quarter 1979.
2. Line Items 1, 2, 3 and 4 are incremental and relative to current oil operations.
3. Unit operating costs based on projected annual demand of 1.32 x 10^{12} Btu/yr.

- Disposal costs for Option I are significantly higher than for the other options, clearly showing the cost penalty of sludge disposal.

- Electric costs are highest for Option II but are offset somewhat by cogeneration; Option II shows significant cogeneration savings.

- Coal costs are highest in Option III, due to inefficiencies in the gasification process.

- Significant differences exist among the three options in incremental operating costs, compared to current operations: Option III will cost 20% and Option I 6% more than Option II each year.

4.2 Guideline Cost Comparison

Next, we compare the capital costs developed for these options with those published in the literature. While several sources were reviewed, particular emphasis is placed here on a comparison with Interim Report E-148, Project Development Guidelines for Converting Army Installations to Coal Use, published by CERL.

Capital cost ranges for some 30 items were provided in this CERL report covering small to medium size industrial boiler plants. Our methodology included interpolation for the plant size at Picatinny Arsenal. Further, we adjusted the resultant figures to third quarter CY 1979 for comparison purposes; the line items in our Option estimates were adjusted to distribute the contingency and supervision, insurance and overhead costs. The comparison follows:

CAPITAL COST COMPARISON

STOKER FIRED BOILERS W/FGD

Item	Current Estimate ($$10^3$)	E-148 Estimate ($$10^3$)
Coal Delivery and Handling	2,255	3,500
Boiler Plant	22,900	18,765
Pollution Control	8,500	11,250
Site Work	1,800	-
TOTAL	34,455	33,515

While differences exist in individual line items, the overall totals compare favorably. Coal delivery and handling, an item which shows considerable variance, is very dependent on site conditions and is more difficult to generalize than the other factors. The pollution control item shows substantial difference on a percentage basis and, when compared to costs in other literature, the E-148 cost is the highest by a considerable margin. The line item differences can result from methodology and specific conditions, and considering the purpose and level of estimates, these differences are acceptable.

Direct comparisons for the Fluidized Bed Combustion Boiler Option and the Low-Btu Gasification Option are not readily obtainable. Interim Report E-148 does not include Fluid Bed Boilers or Low-Btu Gasifiers. Thus, if the Coal Delivery and Handling Item is assumed to have no significant change, the only item left for comparison is Pollution Control. Here we find a significant difference between adjusted figures. The I.R. E-148 estimate allows approximately $1.5 million (adjusted) for baghouse and ash handling versus $4.0 million provided in the current estimates.

The stated objective of I.R. E-148 is to provide Facilities and District Engineers with general and technical and economic guidance for developing coal conversion projects. The individuals for whom I.R. E-148 is prepared will bring engineering judgement to their reading of this report, and in consideration of this, the cost guidelines could be improved, as follows:

- Cost ranges should be presented uniformly and clearly set apart from the text.

- A full cost range should be provided. Phrases such as "up to" and "more than" should be avoided.

- The particular sensitivity to cost fluctuation within the estimated range should be mentioned. For example, cost of coal silo varies with the size of the unit and also with sub-surface conditions. The impact of required foundations on a silo can be very great, but the same soil conditions will not have great impact on the cost of the boiler.

- The methodology used in determining the guideline costs should be included.

- In addition to ranges, unit costs should be provided (per lb, per cfm, etc.) so that scale-up is easily achieved (see last column of Tables 4-1, 4-3 and 4-5).

These changes should, in our opinion, bring the usefulness of the cost guidelines up to the high standard set by the text.

4.3 Life Cycle Costs

To evaluate the potential coal conversion and the three options considered, it is necessary to study life cycle costs for the project. Department of Defense data for short-term annual escalation and differential escalation rates are used for this purpose. These and the source materials are summarized in Table 4-7.

The detailed life cycle cost analysis, using current oil operations as the base, for an assumed FY '82 project is provided in the following tables:

- o Option I - Table 4-8
- o Option II - Table 4-9
- o Option III - Table 4-10

A summary of pertinent results is shown below:

Option		Savings Investment Ratio	Discounted Payback Period (Years)	Discounted Life Cycle Project Cost ($\$/10^6$ Btu)
I.	Stokers	3.34	10.6	3.22
II.	Fluidized Bed	3.65	9.8	3.15
III.	Gasification	3.89	9.9	3.61

Oil Firing Status Quo		Base	Base	5.84

where the first two measures are the traditional measures for comparing investments and where the last is a measure of fuel unit cost over the life cycle of the project (see Lines 8, 9 and 10 on Tables 4-8, 4-9 and 4-10).

From this and an analysis of the detailed economics provided, we may conclude that:

- Fluidized bed combustion boilers and coal derived low-Btu gas appear economically

TABLE 4-7
DISCOUNT RATES
FOR
INVESTMENT PAYBACK ANALYSES

Item	Short Term Annual Escalation Rates				Differential Inflation
	FY '79	FY '80	FY '81	FY ' 82	Rates
Construction	7.8%	7.0%	7.0%	7.0%	0%
Labor & Materials	6.4	6.2	5.6	5.6	0
Coal	10	10	10	10	5
Electricity	16	16	13	13	7
Oil	16	16	14	14	8

Source:

NAVFAC P442 "Economic Analysis Handbook" (June 1975).

NAVFAC LTR 44/218785 "Energy Conservation Investment Program (28 February 1977).

NAVFAC LTR 241652Z "Cost Escalation Guidance" (May 1977).

NAVFAC Naval Speedletter, 24 March 1978.

NAVFAC Instructions for Preparation of Economic Analysis, 407 :ARM, 19 March 1979.

TABLE 4-8

PRIMARY AND SECONDARY ECONOMIC ANALYSIS
25 YEAR LIFE CYCLE COSTS

OPTION I: STOKER BOILERS, FLUE GAS DESULFURIZATION, NEW TURBINE GENERATORS

Line	Description	Current Dollars	Escalated Onetime	Escalated Recurring	Year	Long-Term Differential Escalation Rate	Discount Factor	Discounted Cost
1.	Investment	40,308	47,563		2	0	0.867	41,227
2.	Coal Costs	2,750		3,493	4-28	5	12.853	44,902
3.	Net of Cogeneration Electric Costs (Savings)	(466)		(652)	4-28	7	16.612	(10,832)
4.	Operating Labor & Materials	3,776		4,343	4-28	0	7.156	31,075
5.	Total 25 Year Operating Costs							65,145
6.	Total Project Costs							106,372
7.	Oil Status Quo (Current System)	7,200		10,152	4-28	8	18.976	192,658
8.	Energy Available, 25 Years (10^9 Btu)							33,000
9.	Option Unit Cost (6 ÷ 8), (\$/10^6 Btu)							3.22
10.	Oil Status Quo Cost (7 ÷ 8), (\$/10^6 Btu)							5.84
11.	Savings-Investment Ratio							3.34
12.	Discounted Payback Period (Years)							10.59

NOTES: All dollars in 1000's.
Current time is Third Quarter 1979.
Project is assumed for FY '82.

TABLE 4-9

PRIMARY AND SECONDARY ECONOMIC ANALYSIS
25 YEAR LIFE CYCLE COSTS

OPTION II: FLUIDIZED BED COMBUSTION BOILERS, BAGHOUSES, NEW TURBINE GENERATORS

Line	Description	Current Dollars	Escalated Onetime	Escalated Recurring	Year	Long-Term Differential Escalation Rate	Discount Factor	Discounted Cost
1.	Investment	36,537	43,114		2	0	0.867	37,371
2.	Coal Costs	2,750		3,493	4–28	5	12.853	44,902
3.	Net of Cogeneration Electric Costs (Savings)	(127)		(178)	4–28	7	16.612	(2,957)
4.	Operating Labor & Materials	3,000		3,450	4–28	0	7.156	24,688
5.	Total 25 Year Operating Costs							66,633
6.	Total Project Costs							104,004
7.	Oil Status Quo (Current System)	7,200		10,152	4–28	8	18.976	192,658
8.	Energy Available, 25 Years (10^9 Btu)							33,000
9.	Option Unit Cost (6 ÷ 8), (\$/10^6 Btu)							3.15
10.	Oil Status Quo Cost (7 ÷ 8), (\$/10^6 Btu)							5.84
11.	Savings-Investment Ratio							3.65
12.	Discounted Payback Period (Years)							9.84

NOTES: All dollars in 1000's.
Current time is Third Quarter 1979.
Project is assumed for FY '82.

TABLE 4-10

PRIMARY AND SECONDARY ECONOMIC ANALYSIS
25 YEAR LIFE CYCLE COSTS

OPTION III: GASIFICATION PLANT, BOILER RETROFIT, EXISTING TURBINE GENERATORS

Line	Description	Current Dollars	Escalated Onetime	Escalated Recurring	Year	Long-Term Differential Escalation Rate	Discount Factor	Discounted Cost
1.	Investment	28,336	33,436		2	0	0.867	28,982
2.	Coal Costs for Option	3,929		4,990	4-28	5	12.853	64,146
3.	Electric Costs	160		224	4-28	7	16.612	3,721
4.	Operating Labor & Materials	2,713		3,119	4-28	0	7.156	22,319
5.	Total 25 Year Operating Costs							90,186
6.	Total Project Costs							119,168
7.	Oil Status Quo (Current System)	7,200		10,152	4-28	8	18.976	192,658
8.	Energy Available, 25 Years (10^9 Btu)							33,000
9.	Option Unit Cost (6 ÷ 8), ($/$10^6$ Btu)							3.61
10.	Oil Status Quo Cost (7 ÷ 8), ($/$10^6$ Btu)							5.84
11.	Savings-Investment Ratio							3.89
12.	Discounted Payback Period (Years)							9.94

NOTES: All dollars in 1000's.
Current time is Third Quarter 1979.
Project is assumed for FY '82.

competitive assuming, as we have here, that the existing boilers are not replaced for Option III. Obviously, doing so would downgrade the economics of the gasification system. Both options offer economic advantages over stoker boilers with flue gas desulfurization.

- Stokers with flue gas desulfurization incur significant capital and operating cost penalties. The first arises predominately from the scrubber and sludge silos and tanks; the latter occurs because of the significantly higher waste disposal costs for the sludge material.

4.4 Recommendations

The power plant at Picatinny Arsenal is old by industrial standards and replacement with conversion to coal appears to be economically viable. The three options studied are technically feasible.

This preliminary analysis indicates the prudent choice to be Option II, Fluidized Bed Combustion (FBC). On a life-cycle basis, it appears that FBC and gasification are competitive. However, several differences in the options exist:

- The FBC option includes new equipment while the gasification assumes retrofit of both boilers and turbines. A greater degree of system reliability is probable with the FBC option as compared with the older equipment.

- FBC units are just now becoming commercially available from reliable U.S. based manufacturers although full commercialization awaits additional projects and on-line experience. Availability of gasification equipment is less certain and firm guarantees unavailable.

- A great degree of capacity redundancy does not exist with present equipment, making continued operation during down-time at average demand quite difficult.

- Gasification is an emerging technology with few U.S. based plants from which to gain operating experience. Costs are less certain than for the direct-fired options.

- Environmental regulations for gasification plants are not formulated. Therefore, attaining required approvals is tenuous and new regulations could have a significant impact on costs.

Considering the above, and without a significant economic advantage favoring gasification, we cannot recommend this option at this time.

With the continuing demonstration of FBC technology and its improving commercialization picture, we would recommend implementation of Option II: provision of three new, 100,000 lb/hr fluidized bed combustion coal boilers with new turbine generators at Picatinny Arsenal.

BIBLIOGRAPHY

1. Coal Gasification Quarterly Report, U.S. Department of Energy, Washington, D.C., September, 1979.

2. Coal Liquefaction Quarterly Report, U.S. Department of Energy, Washington, D.C., September, 1979.

3. C. Blazek, N. Baker, R. Tision, "High-Btu Coal Gasification Processes", Argonne National Laboratory, Argonne, Illinois, January, 1979.

4. N. Baker, C. Blazek, R. Tision, "Low and Medium-Btu Coal Gasification Processes", Argonne National Laboratory, Argonne, Illinois, January, 1979.

5. "Cost Comparison Study, Industrial Size Boilers", Davy McKee Corporation, U.S. Department of Energy, Washington, D.C., October, 1979.

6. Conference Papers, Coal Technology '79 Conference, Houston, Texas, November, 1979.

7. Coal Energy Conversion Options for Navy Bases; Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, California, December, 1978.

8. Plant Betterment and Coal Conversion Study for Picatinny Arsenal; Department of the Army, New York District, Corps of Engineers; Pope, Evans and Robbins Incorporated, February, 1980.

APPENDIX C

POWER PLANT COAL CONVERSION STUDY -- DIRECT COMBUSTION, LIQUEFACTION, GASIFICATION: UNITED STATES MILITARY ACADEMY, WEST POINT, NY

PREPARED UNDER

Purchase Order DACA 88-79-M-0254

by

POPE, EVANS AND ROBBINS

TABLE OF CONTENTS

1.0 INTRODUCTION

The United States Army Construction Engineering Research Laboratory has been developing a considerable data base for conversion to coal as the primary fuel at U.S. Army facilities. This study forms a part of that continuing effort. The scope of this study is to assess the technical and economic feasibility of converting the heating and power systems to coal as the primary fuel at the United States Military Academy at West Point, New York. Oil firing capability would be retained to assure operation if coal became unavailable for a brief time.

Consideration is given to both current and advanced coal systems including direct combustion (in suspension, on a grate and fluidized bed combustion) and production and firing of gas and liquid derived from coal. Two concepts of coal conversion alternatives are analyzed and evaluated. Advanced technologies have been limited to those that would be suitable for design within the next two years, as operating plants and not as demonstration projects.

The U.S. Military Academy is a facility encompassing some 16,000 acres of which over 1000 acres are developed. Ninety buildings representing six million square feet of heated area are served by two boiler plants: a small plant for laundry facilities and a large plant for all other facilities. The larger plant, providing steam for 5,860,000 square feet of heated area is the subject of this study.

The main boiler plant, Building 604, has a capacity of 598 x 10^6 Btu per hour. The plant operates on No. 6 fuel oil. Alternative energy sources have been investigated in the past, with gas identified as the only possible substitute for oil. With both fuel oil and natural gas becoming increasingly difficult and expensive to obtain, we have investigated the methods by which coal could be used at West Point.

Historic fuel and steam usage patterns have been established and projections of future use have been made. It is expected that any anticipated load growth will be offset by an ongoing energy conservation program. Therefore we can assume that no change in present peak or average loads will occur in the foreseeable future. Table 1-1 shows the fuel and load requirements.

In reviewing the possibilities of coal conversion, the existing plant, equipment and site must be evaluated and alternatives sought, where necessary. These evaluative factors are discussed in Section 2.0 of this report. Section 3.0 deals with the application of identified technologies to the specifics of West Point. The economic analyses is provided in Section 4.0.

Current literature has been reviewed in preparation of this report. A bibliography is appended.

TABLE 1-1

STEAM AND FUEL REQUIREMENTS

I.	STEAM			
	Annual	620,000,000 lb/year		
	Peak	185,000 lb/hr		
	Average	71,000 lb/hr		
II.	FUEL*	<u>Oil</u>	or	<u>Coal</u>
	Annual	5,000,000 gal/yr		30,300 tons/yr
	Peak	1,655 gal/hr		10.0 tons/hr
	Average	570 gal/hr		3.5 tons/hr

*Based on fuel oil at 145,000 Btu/gal and coal at 12,000 Btu/lb.

2.0 GENERAL DISCUSSION OF OPTIONS

The desirability of converting to coal from gas or oil thereby extending natural resources and reducing dependency on imported fuel is well established. The feasibility of such a conversion requires rigorous investigation of alternatives before an assessment can be made. While many alternatives exist, there are three major conceptual methods for deriving usable energy from coal:

- direct firing;
- conversion of coal to gas with subsequent firing;
- conversion of coal to liquid with subsequent firing.

An assessment of the use of these methods must take into account, in addition to the capital and operating costs, the following factors:

- ability of the process to meet energy demand efficiently;
- equipment redundancy in existing plant to allow continued operation during modification;
- ability of existing equipment to be retrofitted;
- available area within the existing plant to allow for conversion;
- available area around the existing plant for storage and coal handling;
- alternative sites.

Each of the evaluative factors affect the overall assessment differently. For example, should an existing plant not be large enough to allow for a conversion to a specific process, this would be of major concern. This concern would be lessened if an alternate site could be found and almost eliminated if a suitable area existed adjacent to the present plant to allow for efficient conversion. All of the factors have this interrelationship, with the exception of the first: the ability of the method to meet the energy demand efficiently. Of the three methods considered, only direct-firing of coal has both been historically proven and can be sized to produce steam in a range required at the U.S. Military Academy. Gasification of coal, in its low-Btu and medium-Btu forms can also be sized to efficiently meet energy demand, but is only currently establishing an operating record. Liquefaction of coal requires a facility of relatively large size to operate efficiently; an energy demand in the range of that required at the U.S. Military Academy would not be expected to operate efficiently for any long term. When this factor is coupled with the state-of-the-art of liquefaction, as a developing technology, further consideration of converting coal to liquid fuel at West Point must be eliminated. Should a community or utility sized plant be considered in the future, assuming other users would be interested in pooling resources, this technology might be reinvestigated.

2.1 Equipment Redundancy

The existing plant must be reviewed from several points-of-view. Perhaps the most important aspect is the redundancy of existing major equipment. The desired redundancy is such that, for example, one boiler can be removed from service for the period of time required for retrofitting or replacement without adversly affecting the energy supply to the facility.

The U.S. Military Academy Power Plant, Building 604, contains two 200,000 pound per hour (lb/hr) boilers and one 180,000 lb/hr boiler. The peak demand at West Point is 185,000 lbs per hour and the average demand is 71,000 lbs per hour. Clearly, sufficient redundancy exists to remove a boiler from service for retrofit or one-for-one replacement.

2.2 Retrofit of Existing Plant

We next consider the possibility of retrofitting the existing plant as a less costly alternative to replacement. In the general case such retrofit would include a complete new installation of coal handling and storage equipment and facilities, as well as the actual modifications to the boilers. In general, the retrofit would include:

- installation of spreader stoker and grate equipment, generally involving the removal of the oil burners to accommodate this equipment;
- addition of ductwork and fans to provide sufficient air to the area beneath the coal grate;
- modifications to combustion control systems;
- ash collection and reinjection systems;
- emissions control systems, which may include cyclone collectors, electrostatic precipitators or fabric filters and flue gas desulfurization equipment;
- ash and chemical storage space and loading facilities.

The new coal handling equipment, which would be required for either retrofit or replacement includes:

- coal receiving and unloading facilities;
- conveyor systems;
- scales, hoppers and chutes;
- storage facilities;
- coal spreader with feeder assembly;
- leachate control and treatment facilities.

In considering gasification of coal, new handling equipment similar to that needed for direct firing would be installed. In addition to boiler modification, a gasification plant would be required.

A typical gasification plant would include the following basic systems:

- coal pretreater (not required in some systems with certain types of coal);
- gasifier;
- steam supply (source steam, waste product boiler or integral systems);
- air supply (for low-Btu gas);
- oxygen supply (for medium and high-Btu gas);
- slag and char removal, handling and storage;
- gas stream clean-up (which includes some or all of the following equipment: cyclone collectors, scrubbers, electrostatic precipitators, desulfurization system, oil, tar and sulfur storage);

- shift converter (high-Btu gas);
- methanator (high-Btu gas);
- gas distribution system.

Requirements for systems and equipment vary with the specific process, type of coal to be used and end use of the gas product. For example, coal pretreatment is not required for many non-caking coals and certain gasifiers; gas stream clean-up requirements may not include desulfurization if low sulfur coal is used, and particulate removal requirements vary with end use.

Boiler modification from oil to gas firing is relatively simple for high-Btu gas and somewhat more difficult for low and medium-Btu gas, in the general case, because tolerances for efficient combustion are narrow. The burner and combustion controls must be replaced or, at least, revamped.

Low-Btu gas is relatively inefficient when combusted directly because of low flame temperature and finds better application in industrial processes, although it has been successfully used for heating on a demonstration basis. Low-Btu is well suited for use in gas turbines, but an extremely clean gas stream is needed to prevent particulate buildup and turbine blade damage. Medium-Btu gas is manufactured by processes similar to low-Btu gas, with oxygen substituted for air. This process is more efficient than the low-Btu process, but requires the construction and operation of an oxygen plant. Both types of gases are processes through gasifiers which are becoming increasingly commercially available in small enough sizes to allow multi-train modular installation for the typical demand at West Point. High-Btu gas is processed on a much greater scale than the low and medium-Btu gases

and cannot be efficiently produced at a scale to match the demand level under consideration.

In addition to the retrofit and new equipment necessary to use gasified coal, provisions must be made to collect and store by-products, both saleable and waste, that result from these processes and to store sufficient quantities of gas to satisfy demand in the event of outages.

The West Point Power Plant was formerly coal-fired, but none of the equipment needed for reconversion to coal-firing or handling coal for gasification is currently in place. The railroad tracks, necessary for transportation, appear to be in operational condition. All other facilities, from unloading outward, must be constructed.

The retrofitting of the boilers has been discussed in a general sense. Now consider the specific boilers in place at West Point. There are two major boilers, each rated 200,000 lb/hr, which are oil-fired, D-type units, built in 1966. The third is an oil-fired unit rated at 180,000 lb/hr, built in 1938, originally designed to burn coal and converted to oil. Reconversion of the older unit is not considered cost effective. The two newer units can not be retrofitted for coal-firing due to the tube configuration and space requirements of these D-type units.

2.3 Replacement of Existing Equipment

Since retrofitting of the existing plant is not feasible, and sufficient redundancy exists to allow replacement of equipment on a one-for-one basis, this must be the next consideration. Investigation of this possibility within the existing structure yielded negative results. Preliminary boiler sizing indicates that three boilers rated at 120,000 lbs per hour each would meet the range of steam demands efficiently, with flexibility to provide the required steam

using one or two units and reserving the third for standby. If a grate type coal-fired boiler rated at 120,000 lb/hr was substituted for one of the existing 200,000 lb/hr units, there would not be sufficient space. The new unit would have a grate measuring approximately 20 feet wide by 20 feet long, to permit the normal loading rate of 30 pounds of coal per hour per square foot of grate surface. A boiler with a grate of these dimensions could not fit within the existing 18'-6" x 19'-0" column bay spacing. Further, physical requirements of the ash removal system would make the unit too high for the existing space.

Other methods of firing coal can be designed with boilers of smaller dimensional size than a grate-type boiler. Both fluidized bed and pulverized coal boilers are in this category. Again, not enough space exists. While the fluidized bed boiler, with bed dimensions of 20 feet wide and 14 feet long could physically occupy the space vacated by the removal of D-type boilers, auxiliary equipment required for operation would extend beyond the space available. Space exists for the pulverized coal-fired boiler; however, floor area for the pulverizing equipment and the height available are insufficient.

2.4 Site Constraints at the Existing Plant

With no possibility of replacing the boilers within the Power Plant Building, we next consider expansion adjacent to or in the immediate vicinity of the existing building.

The most important site requirements for direct firing or gasification of coal include accessibility by rail; sufficient area for stroage of coal, ash and by-products, if any; and environmental considerations. The railroad track is in place and appears to be in operational condition, satisfying accessibility criteria.

Good practice demands that a thirty-day supply of coal be stored on-site, and that sufficient space be allocated for storage of a ten-day production of ash and by-products from the gasification process. In addition, the plant should have the capability of burning fuel oil, on a standby basis, to assure reliability. Thus, fuel oil storage is also required.

The existing plant is located on a bluff overlooking the Hudson River. The land formation, dropping to the river and rising sharply away from the river, limits any expansion to the east or west. Northerly expansion is limited by existing buildings, necessary to the Academy's operation, and southerly expansion is restricted to the former coal pile area. This area would be sufficient for storage, but not for both storage and an expanded plant. The area is further restricted by the existence of three large above-ground fuel oil storage tanks which occupy the site of the original coal pile. Two fuel oil day tanks further restrict the site. If removal of these tanks were considered cost effective, land formation and sub-surface conditions would remain an obstacle to development. Therefore, another site must be considered for development of a coal conversion option. Figure 2-1 indicates the area requirements for a conversion to coal firing, including handling and storage and an expanded power plant at the site of Building 604. Figure 2-2 indicates, at the same site, the area requirements for a gasification plant including the necessary ancillary equipment.

2.5 Alternate Sites

A prime site requirement is accessibility to railroad transportation. Conrail trackage exists along the Hudson River, at the edge of the Military Academy site. Following the tracks in a northwesterly direction, a potential site can be identified at the end of the Target Hill Athletic

DIAGRAM OF SITE CONSTRAINTS
FOR FBC PLANT AT POWER PLANT SITE

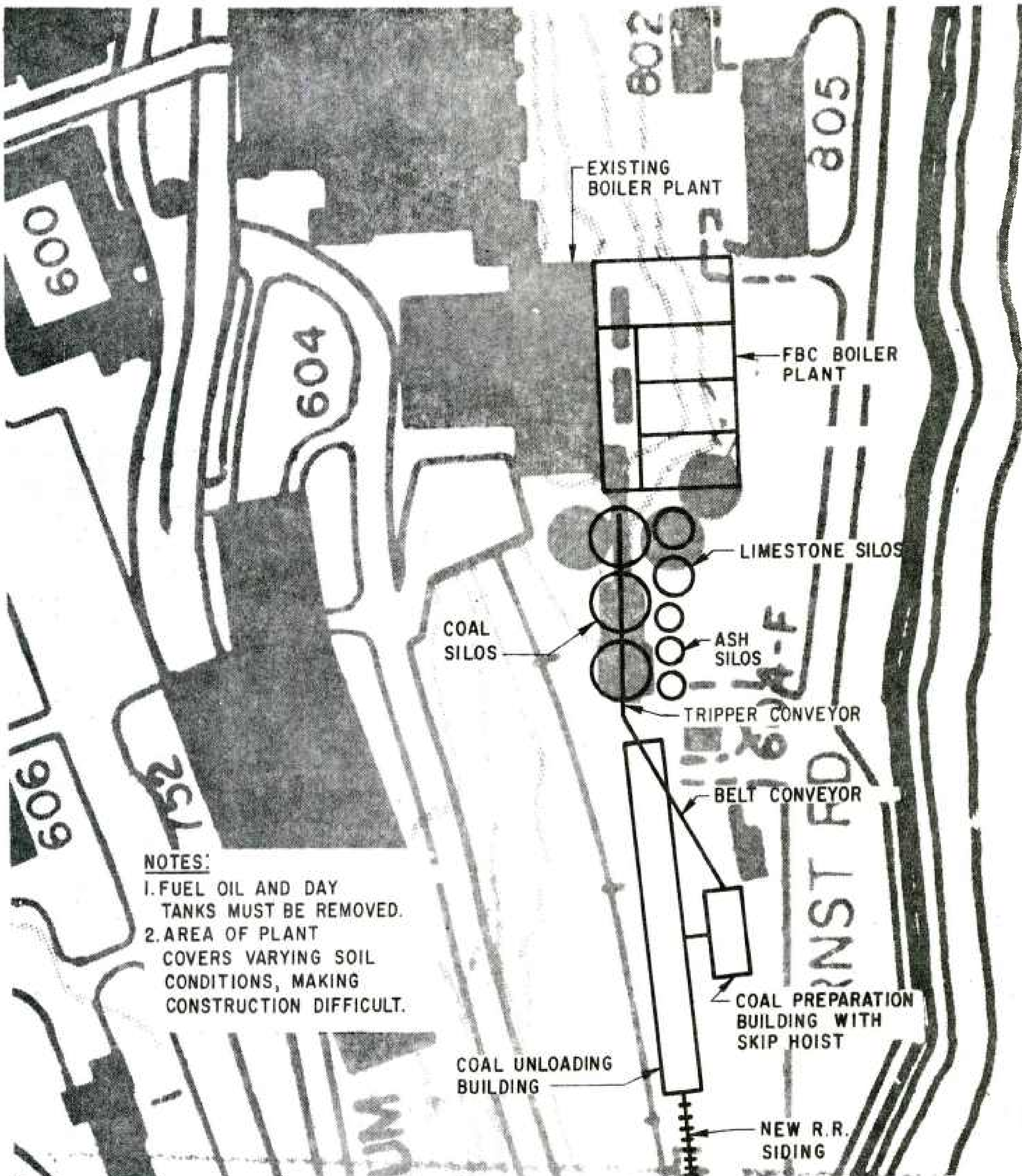


FIGURE 2-1

REQUIRED AREA FOR NEW GASIFICATION PLANT AT BOILER PLANT SITE

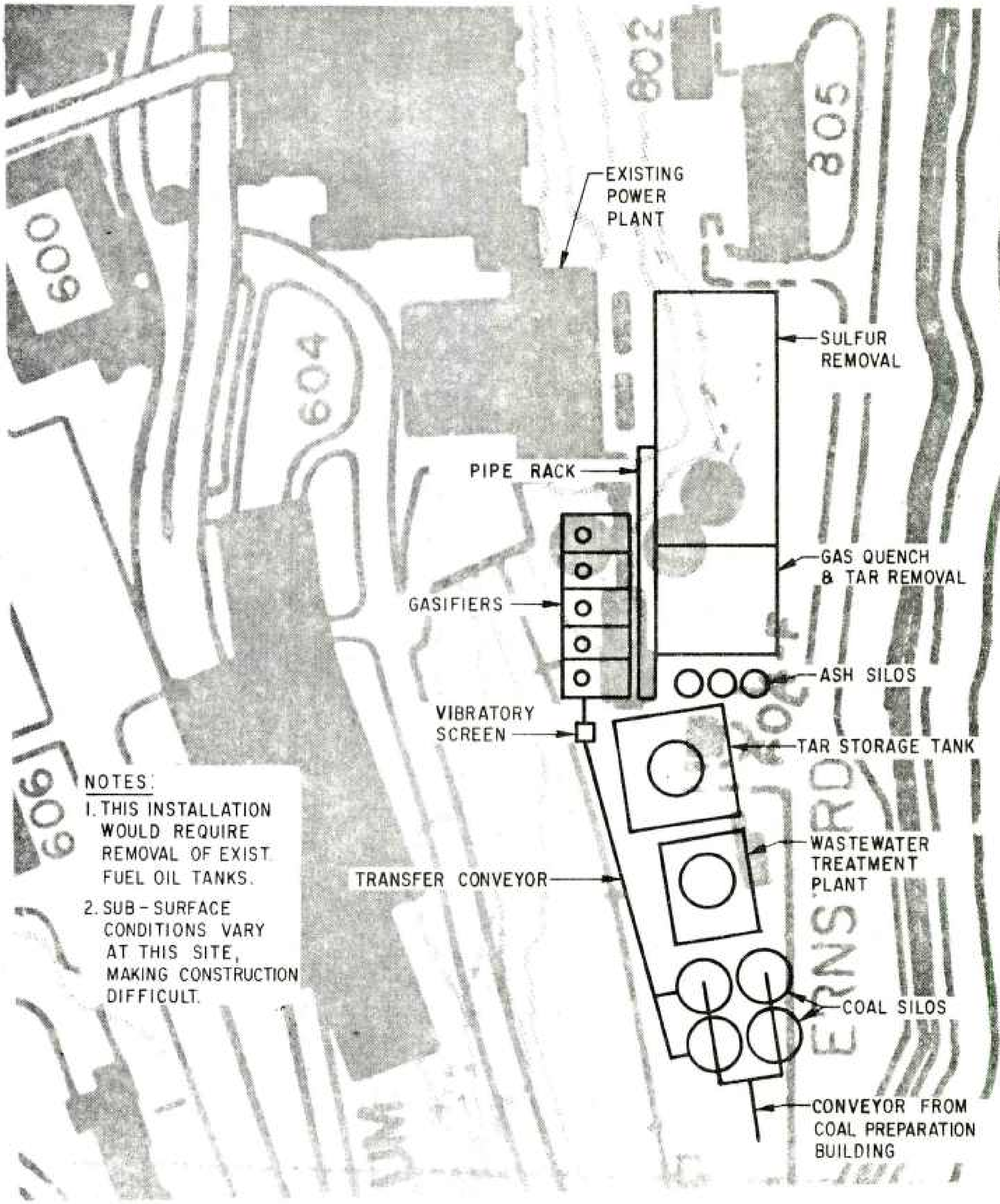


FIGURE 2-2

Field. This site is not only accessible to the railroad, but has needed utilities in place and is of sufficient size for development of plant, storage facilities and ancillary requirements such as roads, parking, etc. This site does have some disadvantages. It is remote from the existing plant and it is located relatively close to a residential area. While these problems are cause for concern, they are not insurmountable, and will be discussed in the following section.

2.6 Summary of Options Selection

Figure 2-3 is a summary of the above discussion. It compares, on a simplified "yes-no-maybe" basis, the various coal-use options against the major factors used in the evaluation. Displayed graphically is the difficulty of using the existing plant or surrounding area, the equipment redundancy beneficial for planning replacement, alternate site factors and efficiency of the process for demand. Naturally not all of these factors are equally weighted. As discussed, the output of high-Btu gas or synthetic liquid fuel oil is inherently inefficient with respect to demand, a fact sufficient to eliminate consideration of these processes. The three main processes: direct firing of coal, low-Btu and medium-Btu gasified coal; are each considered potentially viable and should be further explored for the U.S. Military Academy at West Point.

EVALUATIVE FACTORS FOR COAL CONVERSION PROCESSES

U.S. MILITARY ACADEMY AT WEST POINT

COAL CONVERSION PROCESSES / EVALUATIVE FACTORS	DIRECT COAL FIRING	LOW-BTU GASIFICATION	MEDIUM-BTU GASIFICATION	HIGH-BTU GASIFICATION	LIQUEFACTION
PROCESS EFFICIENCY FOR DEMAND	●	●	●	◒	○
EXISTING EQUIPMENT REDUNDANCY AT PLANT	●	●	●	●	●
RETROFIT POSSIBILITY OF EXISTING PLANT	○	◒	◒	●	●
SUFFICIENCY OF EXISTING PLANT AREA	○	○	○	○	○
SUFFICIENCY OF EXISTING SITE AREA	○	○	○	○	○
AVAILABILITY OF ALTERNATE SITES	●	◒	◒	●	●

LEGEND:

● POSITIVE RELATIONSHIP

◒ INTERMEDIATE RELATIONSHIP

○ NEGATIVE RELATIONSHIP

FIGURE 2-3

3.0 APPLICATION TO WEST POINT

The viable options for coverting from fuel oil to coal at the U.S. Military Academy are direct firing of coal or gasification into low-Btu or medium-Btu gas. Either process can be implemented at the Target Hill site. Direct firing of coal at Target Hill would result in the production of steam and its export in an express main to the existing Power Plant for use in the turbines and for distribution. If direct firing at Target Hill is implemented, all boiler activity at the existing power plant would discontinue. Alternatively, a gasification plant could be installed at Target Hill with an express main to deliver the process gas to the Power Plant. The existing boilers and controls would be modified to burn gas.

3.1 Environmental Considerations

Environmental constraints specific to the Target Hill site, in addition to normal regulatory agency controls, involve land formation and adjacent land use. The Target Hill field is a large flat area at approximately 100 feet above mean high tide. Lee Road, a residential collector road several hundred feet from the proposed plant site, is elevated almost 100 feet above this site. The elevation differential is advantageous in that the views of the Hudson River from the residential area will not be despoiled by the bulk of the new facility, but this advantage is not without some drawback. Flue gas from a new boiler plant must be discharged above the tops of the residences, requiring a stack height in excess of 100 feet above normal requirements.

While the on-post residences will view the Hudson River over the top of the new plant, the view over the Hudson River from Constitution Island, an historical site now under development, will have the plant as a backdrop. While technical environmental concerns can be met with engineering

provisions, the concern for the visual environment can be met only by careful site planning, building design and landscaping - and, at its best, can only hope to soften the visual impact, never eliminate it. Thus, a potential conflict exists concerning non-technical environmental considerations. This conflict must be acknowledged and provisions made to address the problem in the planning phase.

Environmental regulations exist covering source fuel and emissions for air pollution as well as discharge components and temperature for water pollution. These regulations, promulgated by all levels of government, have been considered in our analysis of the various systems. Table 3-1 summarizes the applicable air pollution standards for coal-fired boilers. No standards for the gasification plant exist at this time. If standards were promulgated, we feel they would be similar to 40CFR60, Subpart J, Section 60.100 of the Primary National Air Standards, which we have considered in this report.

3.2 Storage Considerations

Production of steam or gas at Target Hill requires that coal be received and stored at the Plant site. Conrail trackage is available, but a siding must be constructed. A trackhouse, thawpits and unloading facilities are required. The trackhouse for unloading is provided to protect against escape of fugitive dust during off-loading. The coal should be stored in the vicinity of both the trackhouse and plant.

A variety of coal storage techniques are available. In order of increasing costs, these are:

- open pile
- uncovered, walled enclosure
- silos
- reclaim building

TABLE 3-1

SUMMARY OF APPLICABLE AIR POLLUTION STANDARDS FOR COAL FIRED BOILERS

A. Emissions[1]

Smoke[2]	Some visible smoke permitted
Particulates[3]	0.33 lb/10^6 Btu heat input
Sulfur Dioxide[3]	3.8 lb/10^6 Btu heat input

B. Sulfur Content of Compliance Fuel: 2.3%

1. May not significantly deteriorate air quality. See 40CFR50.
2. Exclusive of water vapor.
3. Heat input is the sum of all boiler inputs discharging through a single stack.

Although coal was stored in the open when West Point originally fired coal, in light of present environmental considerations, open storage must be considered unacceptable. A walled enclosure to a height of 12 feet would require an allocation of a space 120 feet by 230 feet for a 30-day supply of coal. The third and fourth methods, while providing for completely covered storage, need only be employed when the facility must meet stringent environmental regulations, when weather conditions require enclosed storage or when space considerations govern. For this study, silo storage is selected since fugitive dust from the pile would be objectionable, and land in this location is at a premium. Three silos will be required for a 30-day coal supply, with each silo measuring approximately 40 feet in diameter and standing approximately 100 feet tall.

From an unloading pit, coal will be lifted onto a stocking out conveyor. Loadout system will be sized at 100 tons per hour to move railroad cars rapidly through the system. Coal will be reclaimed from silos using mass flow screws with inventory on a first-in-first-out basis. Coal will be moved into a new boiler plant bunker storage at the rate of 40 tons per hour, four times the maximum burning rate. This will permit idle time for preventive maintenance and allow the bunkers to be filled in one shift per day. For synthetic fuel production the infeed rate will be selected as required by the process, and will probably be in the range of 50 tons per hour. Synthetic fuel, because of inefficiencies inherent in the processes, will require a greater volume of coal storage than required for direct firing, and a fourth silo will be provided.

Storage is sized to provide 30 days fuel supply at peak load. According to the data on Table 1-1, this would require 7200 tons for direct coal firing and 9000 tons for gasification.

However, such volumes of coal would impact the limited available land at the site, see Sections 2.4, 2.5 and 3.6. Since the boilers to be selected will be able to fire oil as well as coal, it is recommended that fuel storage be provided by a combination of coal and oil. Sizing of the required silos indicates that reasonable structures obtain with an 80%/20% coal/oil split. Thus we would store 5760 tons of coal for direct firing and 7200 tons for gasification. Since we will be retaining the existing plant and fuel oil storage (see Section 3.6), no additional provision need be made for the oil.

Coal will be elevated on a belt conveyor into the plant bunker area. The bunkers will be fed by a tripper conveyor to spread coal for use by each boiler. The shape of the bunker bottom will depend on the method of firing the fuel. Interposed between the pile and the bunkers will be a crusher to prevent large sized material from passing into the system. The crusher will be protected by an electro-magnet to remove tramp iron. Other large uncrushables may be removed after inspection at a check screen. Only one day of in-plant storage is anticipated, with an underbunker conveyor system needed to assure flow to the boiler being fired.

3.3 Boiler Types and Related Environmental Control Equipment

Direct firing of coal can be accomplished using stoker boilers, pulverized coal boilers or fluidized bed combustion units. Recalling that satisfying demand with flexibility, efficiency and back-up requires three boilers sized at 120,000 pounds per hour, we review the boiler types with respect to this capacity rating. Pulverized coal units are inefficient in the size range required here; maintenance costs are also high. Therefore, pulverized coal boilers are not considered for this installation. Both stoker and

fluidized bed boilers are suitable for this application. Both types of boilers are proven technology with stokers having been used continuously for many years. While fluidized bed technology is rooted in the past, development for coal combustion has not been refined until the need for pollution control was imposed. After several years of development, commercial units are available and competitive, both economically and reliably, with stoker boilers.

The stoker boiler discharges fly ash in excess of permissible emissions and therefore requires environmental control. A shortage of low sulfur coal should be anticipated, at least at competitive prices, and SO_2 removal should be provided. Separate systems for filtration of fly ash and removal of sulfur are available, but the use of separate systems is generally found to be economical only at utility-size scale. The equipment size proposed at West Point indicates that a system combining both fly ash and sulfur removal would be suitable. The selection of specific flue gas desulfurization equipment should be made during the preliminary design phase of the project and a decision can be made then whether to use a wet or dry system.

The wet system includes a mixing chamber, usually a venturi nozzle that permits intimate contact between the gas and a liquid bath, and combination contact tower (scrubber) and liquid, removal chamber. Particulate matter is carried along with the gas stream, making contact with the chemically treated liquid, and is captured with the chemical reaction precipitates formed in capture of the SO_2 gas. The dry system includes a spray chamber in which flue gas is sprayed with an SO_2 sorbent. Particles, and the result of the chemical reaction between SO_2 and the sorbent, are then trapped on filter media in a baghouse. An induced draft fan is installed downstream of the baghouse, and thus "sees" clean air at a temperature of approximately 150°F.

Both the wet and dry methods require that flue gas be reheated after treatment. Heat is added to permit the gas to form an acceptable plume. On a cold, dry day, the moist air would rapidly condense and fall as rain in the immediate area. In extreme cold, ice crystals would form. Heat can be taken from the boiler in the form of a steam coil in the discharge of the stack, or can be taken from the flue gas. Precise measurement of particulate matter and SO_2 concentration downstream of the process would dictate the quantities of untreated gas that could be added.

A typical stoker/scrubber facility configuration is shown in Figure 3-1.

A fluidized bed boiler requires no flue gas desulfurization process, and thus has an advantage over stoker boilers. Another advantage is size, being smaller than a stoker, a fluidized bed unit when part of a multiple train will have a considerably smaller building envelope. This is important when considering the impact on the visual environment at the Target Hill site.

The fluidized bed boiler uses limestone in the bed to act as a sorbent for sulfur in the coal. The waste product is a dry powder compared to the 50% wet sludge flue gas desulfurization product. All fly ash produced is collected without further processing. The product can be used to alkalize sewage sludge, as a soil conditioner and as a pozzolith. The material rejected from the bed is a mixture of impurities which varies with the coal. It is a sand-like, alkaline powder, mostly calcium sulfate. It may be used as landfill without additional treatment.

Fly ash from the fluidized bed may be collected in a baghouse, permitting the operation to be performed in the dry state.

TYPICAL STOKER FIRED BOILER PLANT WITH FLUE GAS DESULFURIZATION

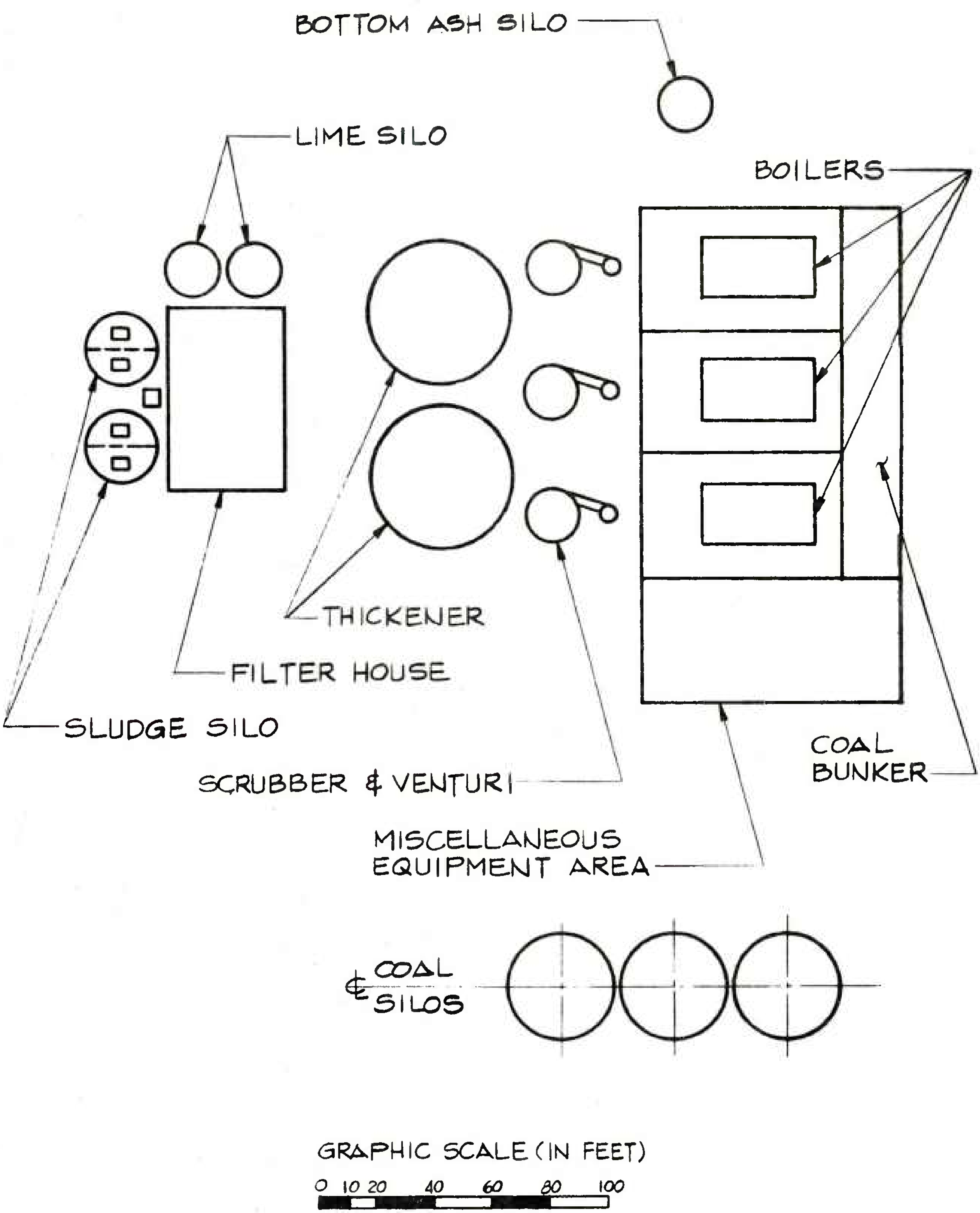


FIGURE 3-1

The problems associated with electrostatic collectors are thus avoided. While some operating difficulties exist with baghouses their technology is a known factor, whereas electrostatic collectors are more subject to the vagaries of dust chemistry and temperature.

Both the bed material and fly ash reject products of fluid bed combustion may be stored in silos until ready for final disposal. Fluidized bed combustion reject products are easier to handle, store and dispose of than those of stoker boilers with flue gas desulfurization which requires lugger pans to haul sludge to sealed landfills. The products of fluidized bed combustion are generally removed in bulk material transport trucks, in the same manner that limestone is delivered.

A typical fluidized bed combustion boiler facility configuration is shown in Figure 3-2.

3.4 Gasification Systems

Gasification of coal can be accomplished in fixed, entrained or fluidized bed gasifiers. The product gas is then processed to remove deleterious material. With some systems, reject material such as sulfur can be reclaimed as a by-product of value. The demand for gas at the U.S. Military Academy would require approximately 250 tons of coal per day to be processed. In this capacity range and with consideration of desirability of a multi-train plant to allow partial operation in the event of breakdown and flexibility to match demand, five small fixed-bed gasifiers would be recommended. Four gasifiers are required to meet maximum load, with the fifth serving a standby function.

During the preliminary design phase a decision must be made concerning the selection of a single to two stage gasifier.

TYPICAL FLUIDIZED BED BOILER PLANT WITH BAGHOUSE

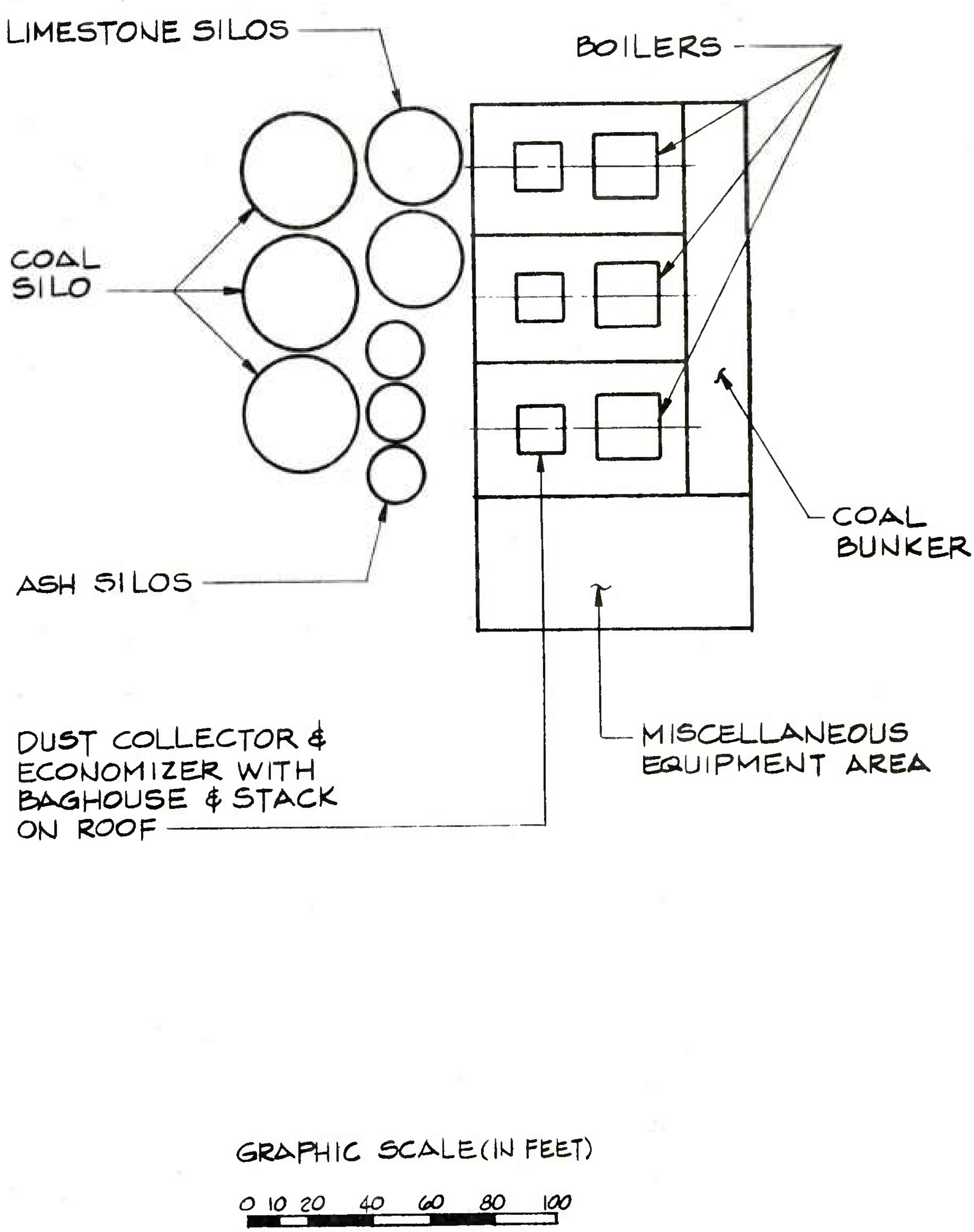


FIGURE 3-2

Both types of units are commercially available and can produce a range of product gasses. The two-stage gasifier permits gas to be taken from both upper and lower chambers. In the upper stage the temperatures are lower, reducing the amounts of tars and oils carried in the gas stream. This minimizes the deposits in piping systems and equipment and reduces the overall clean-up required. Two stage gasifiers are not, however, produced with mechanical stirrers and, therefore, cannot handle strongly caking coal. The single stage gasifier will accept all types of coal without need for pretreatment. Thus the process selected is heavily dependent on the source of fuel.

The gasification process is simple. Coal is fed into a gasifier and is dried, heated and combusted as it migrates through various zones down toward the grate, where it is removed as ash. The gas from combustion arises and is the vehicle which treates the incoming coal. Either air or oxygen is introduced below the grate. If air is used the product is low-Btu gas, with a high heating value of 100 to 150 Btu/scf. When oxygen replaces air the product is medium-Btu gas, with a high heating value of 250 to 350 Btu/scf. If medium-Btu gas is to be produced, the cost of constructing and operating an oxygen plant must be considered. The product gas also requires clean-up prior to firing.

The clean-up process includes particulate, tar, and sulfur removal as well as cooling of the gas. Clean-up systems vary with system design and manufacturer, but all include some or all of the following equipment: cyclones, quenchers, coolers, tar separators, condensers, cooling towers, electrostatic precipitators and desulfurization systems.

By-products vary with both the system and the type of coal, but generally include ash, tar, oil and sulfur. Some of

these by-products, such as sulfur when produced in elemental form, are saleable. Tars produced may be useable in boilers to produce steam required in the gasification process. All by-products must be stored and transported to final disposition.

A typical gasification configuration is shown in Figure 3-3.

3.5 Operating Considerations

Concern for following load exists with both gas and steam production. A stoker fired or fluidized bed boiler can act efficiently at one-third rated capacity. Therefore, a boiler plant with three 120,000 lb/hr boilers can operate over a range of 40,000 to 360,000 lb/hr. A gasifier, of the type under consideration, would have a turndown ratio equivalent to that of the coal-fired unit and, therefore, the two systems are comparable on this basis.

In the event of interruption of coal supply, for either direct-firing or gasification, fuel oil must be kept in reserve. If a new boiler plant is constructed for direct-firing of coal at the Target Hill site, the existing boilers at the power plant would be retained for standby service. With the gasification option, the retrofitted boilers should be equipped with burners capable of firing gas and oil.

3.6 Other Site Problems

The Target Hill site is 2.4 miles from the existing power plant. If steam is produced at Target Hill it must be piped to the power plant for use in turbines and for distribution. If a gasification process plant is constructed at Target Hill, the product gas will require piping to the power plant for firing in the retrofitted boilers. The piping systems for steam and gas are somewhat different, but have some similar requirements. Both systems should be

TYPICAL LOW-BTU GASIFIER PROCESS PLANT

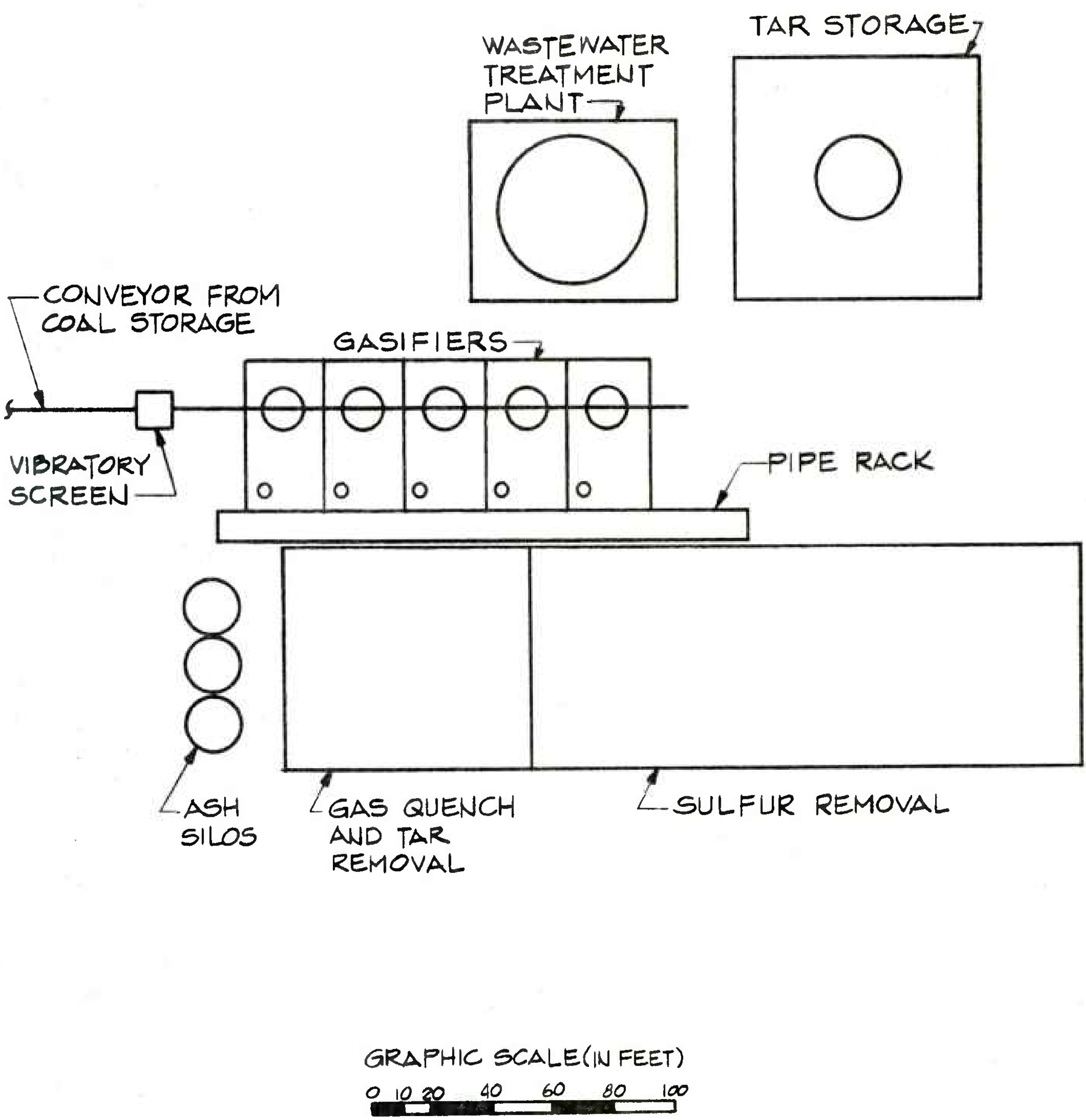


FIGURE 3-3

direct burial, following existing streets where they exist and transversing few fields. In the preliminary design phase various configurations should be tested against cost, for optimization. Cathodic protection against electrolytically active soils should be provided. Both gas and steam piping should be express mains to the power plant and must be designed to operate under pressure: gas at approximately 60 psig and steam at 200 psig. Preliminary engineering has indicated a requirement for two eight-inch diameter pipes for the gas system and two twelve-inch diameter pipes for the steam express main. The steam piping system would also require a condensate return, sized at six-inch diameter. A preliminary piping system layout is shown in Figure 3-4.

3.7 Summary

Two processes are considered viable for further investigation:

- Fluidized bed boilers with baghouses.
- Low-Btu gasification of coal.

Stoker firing with flue gas desulfurization has been excluded because of size considerations at Target Hill. Comparing the plan views in Figures 3-1 and 3-2 indicate this clearly. Medium-Btu gasification has been excluded because, first, capital and operating costs associated with the required recycle plant would penalize this process with respect to the demand at West Point. Second, the oxygen plant space requirements could not be met at Target Hill.

A site plan of the Target Hill area showing a fluidized bed combustion boiler plant is provided in Figure 3-5. A gasification plant at the same site is shown in Figure 3-6.

EXPRESS MAIN LAYOUT FOR STEAM OR GAS

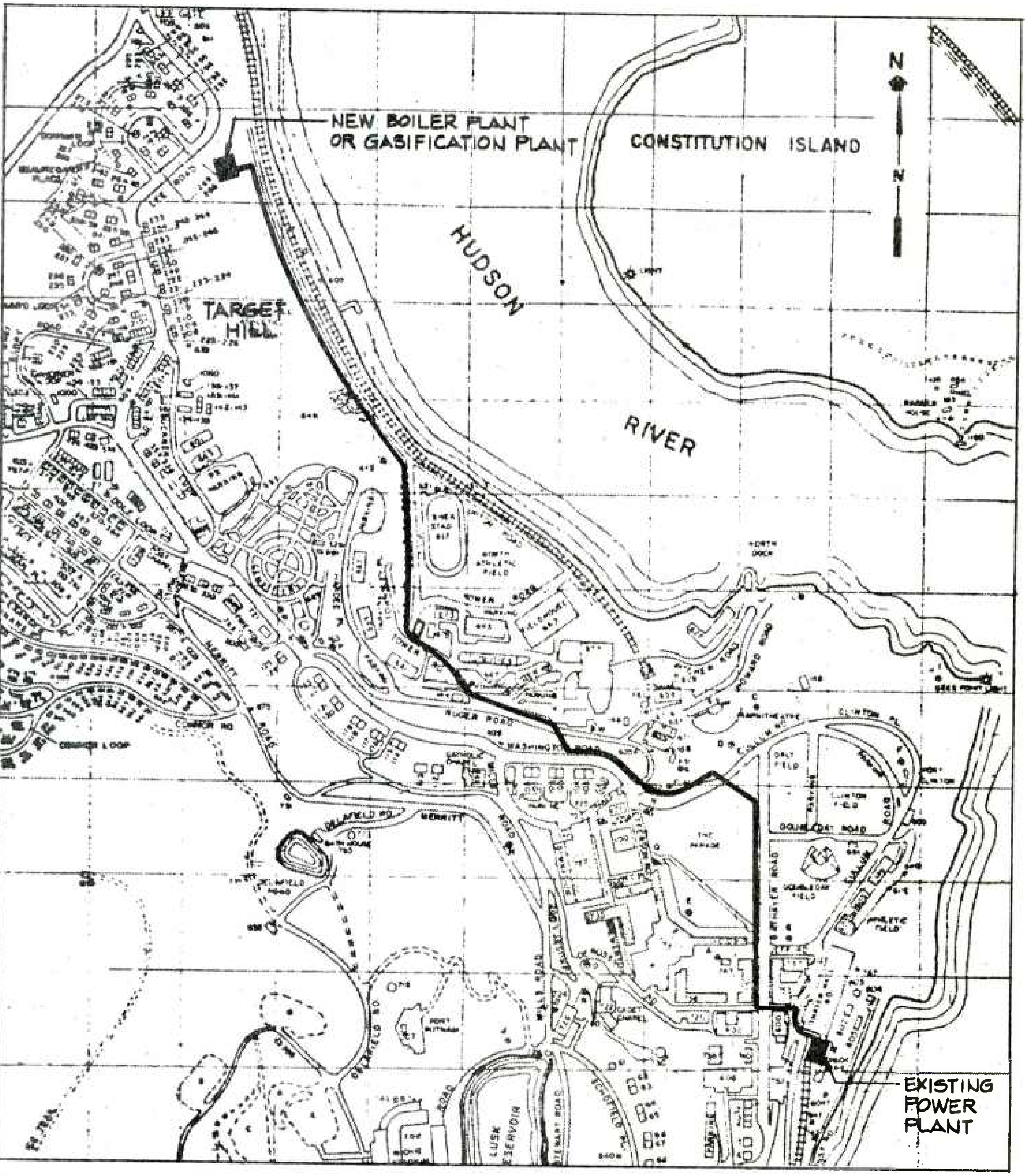


FIGURE 3-4

FLUIDIZED BED COMBUSTION BOILER PLANT
AT TARGET HILL SITE

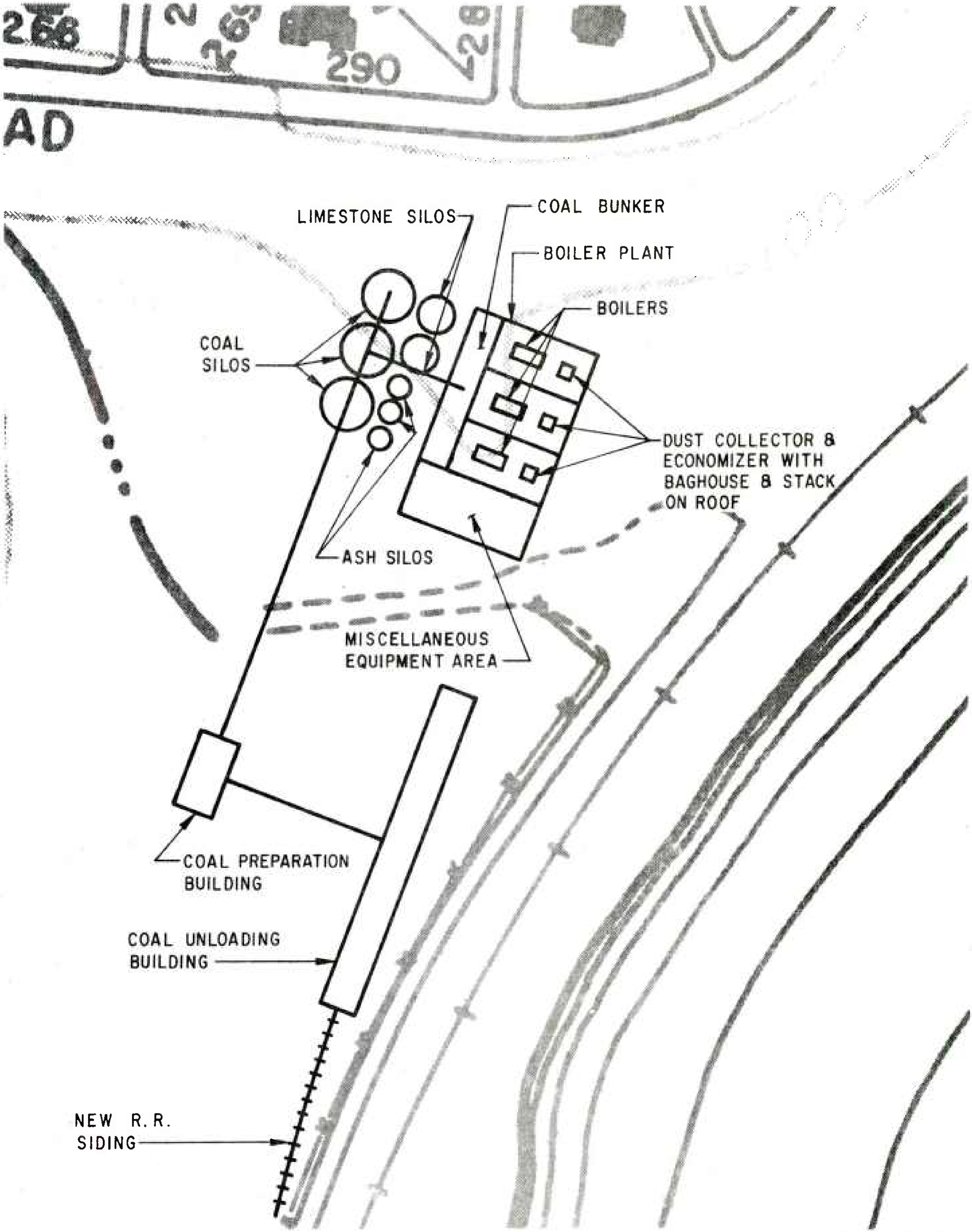


FIGURE 3-5

GASIFICATION FACILITY AT TARGET HILL

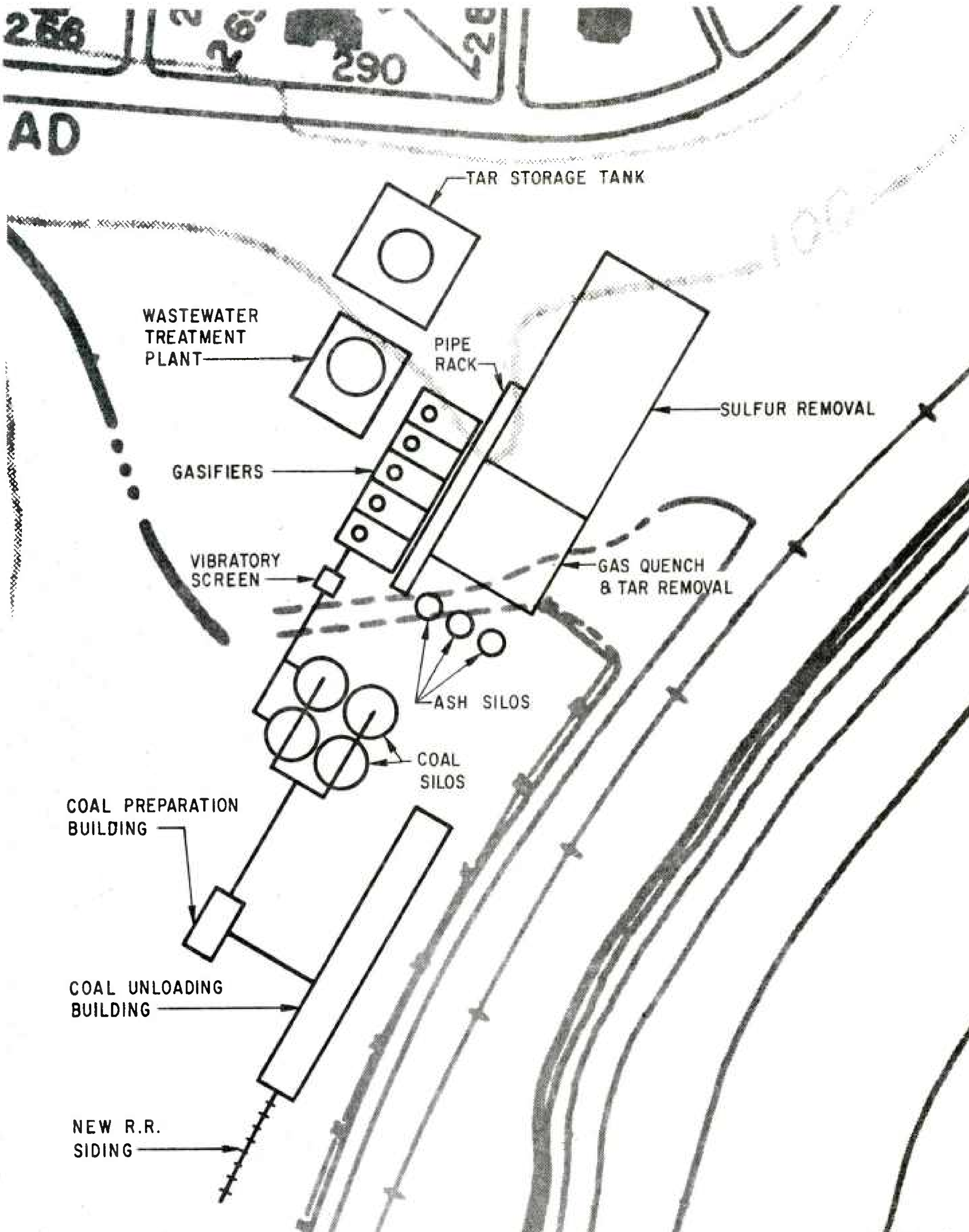


FIGURE 3-6

4.0 ECONOMIC ANALYSES AND RECOMMENDATIONS

The cost analysis presented here was derived on the basis of direct quotation, communications with suppliers and the current literature describing the various systems. The economics are based on the conceptual design and engineering information prepared for each option.

4.1 Cost Analysis

The materials, supplies and labor for plant operation and maintenance were estimated to reflect current practices. Information from previous work was used to prepare both the capital and operating cost estimates for this study. It is useful to set out some of the basic information used here:

- Labor costs are taken at $25,000 annually per individual.
- Repair materials estimated at 2% of capital costs (before application of SIOH).
- Electric costs at $0.05/kWh.
- Lime costs at $15/ton.
- Limestone costs at $15/ton.
- Sludge disposal costs at $30/ton.
- Ash and FBC waste disposal costs at $15/ton.
- Coal costs estimated to be $50/ton delivered.
- Current oil costs taken to be $0.80/gallon.
- By-products from gasification process assumed to have value equal to disposal cost.

- Capital costs include contractor's overhead at 15%, contractor's profit at 10%; general contractors overrides for overhead and profit at 5% and 5%.

- A contingency, applied before SIOH, is included. A factor of 10% is applied to the direct-fired system and 15% is applied to the gasification system. The higher factor is used for gasification because of the uncertainties inherent in a relatively new technology.

The two options that have been found most promising for specific application at West Point are:

- Option I - Installation of a fluidized bed boiler plant at the Target Hill site, with steam exported in express mains to the existing power plant for use in existing steam turbine generators and distribution. Steam production at the existing power plant will be discontinued.

- Option II - Installation of a multi-train gasifier plant at the Target Hill site, with low-Btu gas compressed and exported in express mains to the existing power plant. Implementation of a retrofit of the existing boilers to permit gas firing is necessary.

With both options, fuel oil firing capability will be provided for standby use.

Capital and operating costs for each option have been tabulated: For Option I, capital costs are shown in Table 4-1, and operating costs in Table 4-2; Option II capital costs are displayed in Table 4-3 and operating costs in Table 4-4.

Inspection of these results yields some useful information:

- No significant difference in capital costs for coal handling and delivery exists between the options.

- The boiler plant in Option I and the gasification plant in Option II each represent approximately 50% of the investment cost for their respective option.

- The remote Target Hill location penalizes both options significantly. The pipeline cost is the second largest line item for the fluidized bed option. The gasification option requires a pumping station because of the distance between manufacture and end use point; this is the second largest cost item for Option II. The pipeline cost is the third largest item for the gasification option.

- Significant differences exist between the two options in both operating and capital costs. The annual operating cost of the gasification process is 23% more than for fluidized bed boilers. The total capital costs for fluidized bed boilers exceed the gasification process cost by 22%.

TABLE 4-1

SUMMARY OF CAPITAL COSTS[1]

OPTION I: FLUIDIZED BED COMBUSTION BOILERS

Line Item	Amount	Percent of Grand Total	Unit Cost[2] ($/lb)
1. Coal Delivery and Handling			
Track Work	47	0.1	0.13
Railcar Unloading Building	811	1.9	2.25
Coal Preparation Building	162	0.4	0.45
Conveyor to Storage	156	0.4	0.43
Coal Storage Silos	1,365	3.1	3.79
Silos Hoppers	448	1.0	1.24
Conveyor to Plant	156	0.4	0.43
2. Boiler Plant			
3 Boilers @ 120,000 lb/hr (Includes In-Plant Coal Handling)	23,393	54.0	64.98
3. Pollution Control			
Baghouses	3,197	7.4	8.88
Limestone Storage	1,622	3.7	4.51
Ash Storage	1,123	2.6	3.12
4. Yard Work			
Electric	858	2.0	2.38
Utilities Other Than Electric	286	0.7	0.79
5. Pipeline	3,690	8.5	10.25
Subtotal	37,314	86.2	103.65
Contingency at 10%	3,731	8.6	10.36
Total Capital Cost	41,045	94.8	114.01
SIOH at 5.5%	2,257	5.2	6.27
GRAND TOTAL	43,302	100.0	120.28

1. All dollars in 1000's, costs estimated as of 3rd Quarter 1979.
2. Capital unit costs based on 360,000 lb/hr boiler nameplate rating.

TABLE 4-2

SUMMARY OF OPERATING COSTS[1]

OPTION I: FLUIDIZED BED COMBUSTION BOILERS

Item[2]	Total	Percent of Grand Total	Unit Cost[3] ($\$/10^6$Btu)
1. Labor (14 additional men)	900	21.9	1.24
2. Repair Materials	971	23.6	1.34
3. Disposals	225	5.5	0.31
4. Electric	514	12.5	0.71
5. Coal	1,500	36.5	2.07
GRAND TOTAL	4,110	100.0	5.67

1. All dollars in 1000's, estimated at 3rd Quarter 1979.
2. Line Items 1, 2, 3 and 4 are incremental and relative to current oil operations.
3. Operating unit costs based on projected annual demand of 725 x 10^9 Btu/yr.

TABLE 4-3

SUMMARY OF CAPITAL COSTS[1]

OPTION II: GASIFICATION PLANT AND RETROFIT OF EXISTING BOILERS

Line Item	Amount	Percent of Grand Total	Unit Cost[2] ($/lb)
1. Coal Delivery and Handling			
Track Work	46	0.1	0.18
Railcar Unloading Building	794	2.2	3.15
Coal Preparation Building	159	0.5	0.63
Conveyor to Storage	153	0.4	0.61
Coal Storage Silos	1,782	5.0	7.07
Silo Hoppers	586	1.6	2.33
Conveyor to Plant	191	0.5	0.76
2. Boiler Plant			
Gasifiers (5)	17,490	49.1	69.40
Pumping Station	4,201	11.8	16.67
Boiler Conversion	764	2.1	3.03
3. Pollution Control			
Ash Storage	95	0.3	0.38
4. Yard Work			
Electric	1,349	3.8	5.35
Utilities Other Than Electric	280	0.8	1.11
5. Pipeline	1,470	4.1	5.83
Subtotal	29,360	82.4	116.51
Contingency at 15%	4,404	12.4	17.48
Total Capital Cost	33,764	94.8	133.98
SIOH at 5.5%	1,857	5.2	7.37
GRAND TOTAL	35,621	100.0	141.35

1. All dollars in 1000's, costs estimated as of 3rd Quarter 1979.
2. Capital unit costs based on 252,000 lb/hr gasifier system capacity.

TABLE 4-4

SUMMARY OF OPERATING COSTS[1]

OPTION II: GASIFICATION PLANT AND RETROFIT OF EXISTING BOILERS

Item[2]	Total	Percent of Grand Total	Unit Cost[3] ($/10^{6}Btu)
1. Labor (30 added)	1100	21.9	1.52
2. Materials	675	13.4	0.93
3. Disposals	150	3.0	0.21
4. Electric	960	19.1	1.32
5. Coal	2,143	42.6	2.96
GRAND TOTAL	5,028	100.0	6.94

1. All dollars in 1000's, estimated at 3rd Quarter 1979.
2. Line Items 1, 2, 3 and 4 are incremental and relative to current oil operations.
3. Operating unit costs based on projected annual demand of 725 x 10^9 Btu/yr.

- Comparison of operating costs indicates that the higher cost for gasification is attributed to additional labor and coal required for the gasification process. The higher labor and fuel costs for Option II are offset slightly by the higher electric costs for the fluidized bed option.

- Use of coal represents a significant reduction in the cost of purchased fuel with both options. Estimated reduction in cost of purchased fuel is approximately 52% for Option I and 31% for Option II.

4.2 Guideline Cost Comparison

Next, we compare the capital costs developed for these options with those published in the Literature. While several sources were reviewed, particular emphasis is placed here on a comparison with Interim Report E-148, Project Development Guidelines for Converting Army Installations to Coal Use, published by CERL.

Capital cost ranges for some 30 items were provided in this CERL report covering small to medium size industrial boiler plants. Our methodology included interpolation for the plant size at the U.S. Military Academy at West Point. Further, we adjusted the resultant figures to third quarter CY 1979 for comparative purposes; the line items in our Option estimates were adjusted to distribute the contingency and supervision, insurance and overhead costs.

Note that direct comparisons for the Fluidized Bed Combustion Boiler Option and the Low-Btu Gasification Option are not obtainable since these items are not included in Interim

Report E-148. However, some other individual system comparisons can be made.

The adjusted figure for Coal Delivery and Handling is approximately $3,145,000 for the Options discussed in Section 4.1. (The Gasification Option is slightly less costly than the FBC Option because some of the required equipment is included in the Gasification package price.) The adjusted estimate extrapolated from the I.R. E-148 Guidelines is $3,675,000. These figures compare favorably.

As mentioned above, boiler plant comparisons cannot be made with the items estimated in these Options. The same situation exists for some pollution control items. However, baghouses are common to both the estimate and guidelines.

The Option I estimate includes baghouses at an adjusted cost of $3,700,000. The I.R. E-148 Guidelines estimate this item cost at a maximum of $7.50 per ACFM. For the estimated flow rate here, at approximately 156×10^3 ACFM, the cost would be $1,170,000 or $1,300,000 adjusted. There appears to be a considerable variance between these figures which is not readily explainable.

The stated objective of I.R. E-148 is to provide facilities and District Engineers with general and technical and economic guidance for developing coal conversion projects. The individuals for whom I.R. E-148 is prepared will bring engineering judgement to their reading of this report, and in consideration of this, the cost guidelines in I.R. E-148 could be improved, as follows:

- Cost ranges should be presented uniformly and clearly set apart from the text.

- A full cost range should be provided. Phrases such as "up to" and "more than" should be avoided.

- The particular sensitivity to cost fluctuation within the estimated range should be mentioned. For example, cost of a coal silo varies with the size of the unit and also with sub-surface conditions. The impact of required foundations on a silo can be very great, but the same soil conditions will not have great impact on the cost of the boiler.

- The methodology used in determining the guideline costs should be included.

- In addition to ranges, unit costs should be provided (per lb, per cfm, etc.) so that scale-up is easily achieved (see last column of Tables 4-1, and 4-3).

These changes should, in our opinion, bring the usefulness of the cost guidelines up to the high standard set by the text.

4.3 Life Cycle Costs

To evaluate the potential coal conversion and the two options considered, it is necessary to study life cycle costs for the project. Department of Defense data for short-term annual escalation and differential escalation rates are used for this purpose. These and the source materials are summarized in Table 4-5.

The detailed life cycle cost analysis, using current oil operations as the base, for an assumed FY '82 project is

TABLE 4-5

DISCOUNT RATES
FOR
INVESTMENT PAYBACK ANALYSES

Item	Short Term Annual Escalation Rates				Differential Inflation Rates
	FY '79	FY '80	FY '81	FY '82	
Construction	7.8%	7.0%	7.0%	7.0%	0%
Labor & Materials	6.4	6.2	5.6	5.6	0
Coal	10	10	10	10	5
Electricity	16	16	13	13	7
Oil	16	16	14	14	8

Source:

NAVFAC P442 "Economic Analysis Handbook" (June 1975).

NAVFAC LTR 44/218785 "Energy Conservation Investment Program (28 February 1977).

NAVFAC LTR 241652Z "Cost Escalation Guidance" (May 1977).

NAVFAC Naval Speedletter, 24 March 1978.

NAVFAC Instructions for Preparation of Economic Analysis, 407:ARM, 19 March 1979.

provided in Table 4-6 for Option I and Table 4-7 for Option II.

A standard measure of economic viability, the savings-investment ratio for both options is less than unity, indicating an investment loss at the end of the 25 year life of the plant. Another means of making a similar comparison between the Option costs and status quo costs is to compare unit costs over the life of the project, see Lines 8, 9 and 10 on Tables 4-6 and 4-7. There we see the oil cost is $\$4.31/10^6$ Btu while for fluidized bed boilers it is $\$5.25/10^6$ Btu and for gasification $\$5.83/10^6$ Btu.

Naturally, these results are vitally dependent on the current prices for fuel. Should the oil costs escalate considerably, these economics might be reinvestigated.

4.4 Recommendations

Conversion of the U.S. Military Academy boiler plant from oil to coal firing, using either Option I or Option II alternatives, is technically feasible although potentially environmentally unattractive. However, on an economic basis, investment in coal conversion at West Point is not recommended. Conversion of the boiler plant to gas fired operation, using coal derived gas produced by a local utility or community sized plant might offer energy dollar savings in the future. If sufficient interest can be generated in this possibility, it might be worth exploring.

TABLE 4-6

PRIMARY AND SECONDARY ECONOMIC ANALYSIS
25 YEAR LIFE CYCLE COSTS

OPTION I - FLUIDIZED BED

Line	Description	Current Dollars	Escalated Onetime	Escalated Recurring	Year	Long Term Differntial Escalation Rate	Discount Factor	Discounted Cost
1.	Investment	43,302	49,797		2	0	0.867	43,174
2.	Coal Costs	1,500		1,815	4-28	5	12.853	23,328
3.	Electric Costs	514		668	4-28	7	16.612	11,100
4.	Operating Labor & Materials	2,096		2,348	4-28	0	7.156	16,803
5.	Total 25 Year Operating Costs							51,231
6.	Total Project Costs							94,405
7.	Oil Status Quo (Current System)	3,100		4,092	4-28	8	18.976	103.5
8.	Energy Available, 25 Years (10^9 Btu)							18,000
9.	Option Unit Cost (6 ÷ 8), (\$/10^6 Btu)							5.25
10.	Oil Status Quo Unit Cost (7 ÷ 8), (\$/10^6 Btu)							4.31
11.	Savings-Investment Ratio							0.71
12.	Discounted Payback Period (Years)							-

NOTES: All dollars in 1000's.
Current time is Third Quarter 1979.
Project is assumed for FY '82.

TABLE 4-7

PRIMARY AND SECONDARY ECONOMIC ANALYSIS
25 YEAR LIFE CYCLE COSTS

OPTION II - GASIFICATION

Line	Description	Current Dollars	Escalated Onetime	Escalated Recurring	Year	Long Term Differntial Escalation Rate	Discount Factor	Discounted Cost
1.	Investment	35,621	40,964		2	0	0.867	35,516
2.	Coal Costs	2,143		2,593	4-28	5	12.853	33,328
3.	Electric Costs	960		1,248	4-28	7	16.612	20,732
4.	Operating Labor & Materials	1,925		2,156	4-28	0	7.156	15,428
5.	Total 25 Year Operating Costs							69,488
6.	Total Project Costs							105,004
7.	Oil Status Quo (Current System)	3,100		4,092	4-28	8	18.976	103.5
8.	Energy Available, 25 Years (10^9 Btu)							18,000
9.	Option Unit Cost (6 ÷ 8), ($/$10^6$ Btu)							5.83
10.	Oil Status Quo Unit Cost (7 ÷ 8), ($/$10^6$ Btu)							4.31
11.	Savings-Investment Ratio							0.31
12.	Discounted Payback Period (Years)							-

NOTES: All dollars in 1000's.
Current time is Third Quarter 1979.
Project is assumed for FY '82.

BIBLIOGRAPHY

1. Coal Gasification Quarterly Report, U.S. Department of Energy, Washington, D.C., September, 1979.

2. Coal Liquefaction Quarterly Report, U.S. Department of Energy, Washington, D.C., September, 1979.

3. C. Blazek, N. Baker, R. Tision, "High-Btu Coal Gasification Processes", Argonne National Laboratory, Argonne, Illinois, January, 1979.

4. N. Baker, C. Blazek, R. Tision, "Low and Medium-Btu Coal Gasification Processes", Argonne National Laboratory, Argonne, Illinois, January, 1979.

5. "Cost Comparison Study, Industrial Size Boilers", Davy McKee Corporation, U.S. Department of Energy, Washington, D.C., October, 1979.

6. Conference Papers, Coal Technology '79 Conference, Houston, Texas, November, 1979.

7. Coal Energy Conversion Options for Navy Bases; Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, California, December, 1978.

CERL DISTRIBUTION

Chief of Engineers
ATTN: Tech Monitor
ATTN: DAEN-ASI-L (2)
ATTN: DAEN-CCP
ATTN: DAEN-CW
ATTN: DAEN-CWE
ATTN: DAEN-CWM-R
ATTN: DAEN-CWD
ATTN: DAEN-CWP
ATTN: DAEN-MP
ATTN: DAEN-MPC
ATTN: DAEN-MPE
ATTN: DAEN-MPO
ATTN: DAEN-MPR-A
ATTN: DAEN-RD
ATTN: DAEN-RDC
ATTN: DAEN-RDM
ATTN: DAEN-RM
ATTN: DAEN-ZC
ATTN: DAEN-ZCE
ATTN: DAEN-ZCI
ATTN: DAEN-ZCM

US Army Engineer Districts
ATTN: Library
Alaska
Al Batin
Albuquerque
Baltimore
Buffalo
Charleston
Chicago
Detroit
Far East
Fort Worth
Galveston
Huntington
Jacksonville
Japan
Kansas City
Little Rock
Los Angeles
Louisville
Memphis
Mobile
Nashville
New Orleans
New York
Norfolk
Omaha
Philadelphia
Pittsburgh
Portland
Riyadh
Rock Island
Sacramento
San Francisco
Savannah
Seattle
St. Louis
St. Paul
Tulsa
Vicksburg
Walla Walla
Wilmington

US Army Engineer Divisions
ATTN: Library
Europe
Huntsville
Lower Mississippi Valley
Middle East
Middle East (Rear)
Missouri River
New England
North Atlantic
North Central
North Pacific
Ohio River
Pacific Ocean
South Atlantic
South Pacific
Southwestern

Waterways Experiment Station
ATTN: Library

Cold Regions Research Engineering Lab
ATTN: Library

US Government Printing Office
Receiving Section/Depository Copies (2)

Defense Technical Information Center
ATTN: DDA (12)

Engineering Societies Library
New York, NY

FESA, ATTN: Library

ETL, ATTN: Library

Engr. Studies Center, ATTN: Library

Inst. for Water Res., ATTN: Library

SHAPE
ATTN: Survivability Section, CCB-OPS
Infrastructure Branch, LANDA

HQ USEUCOM
ATTN: ECJ 4/7-LOE

Army Instl. and Major Activities (CONUS)
DARCOM - Dir., Inst., & Svcs.
ATTN: Facilities Engineer
ARRADCOM
Aberdeen Proving Ground
Army Matls. and Mechanics Res. Ctr.
Corpus Christi Army Depot
Harry Diamond Laboratories
Dugway Proving Ground
Jefferson Proving Ground
Fort Monmouth
Letterkenny Army Depot
Natick Research and Dev. Ctr.
New Cumberland Army Depot
Pueblo Army Depot
Red River Army Depot
Redstone Arsenal
Rock Island Arsenal
Savanna Army Depot
Sharpe Army Depot
Seneca Army Depot
Tobyhanna Army Depot
Tooele Army Depot
Watervliet Arsenal
Yuma Proving Ground
White Sands Missile Range

FORSCOM
FORSCOM Engineer, ATTN: AFEN-FE
ATTN: Facilities Engineers
Fort Buchanan
Fort Bragg
Fort Campbell
Fort Carson
Fort Devens
Fort Drum
Fort Hood
Fort Indiantown Gap
Fort Irwin
Fort Sam Houston
Fort Lewis
Fort McCoy
Fort McPherson
Fort George G. Meade
Fort Ord
Fort Polk
Fort Richardson
Fort Riley
Presidio of San Francisco
Fort Sheridan
Fort Stewart
Fort Wainwright
Vancouver Bks.

TRADOC
HQ, TRADOC, ATTN: ATEN-FE
ATTN: Facilities Engineer
Fort Belvoir
Fort Benning
Fort Bliss
Carlisle Barracks
Fort Chaffee
Fort Dix
Fort Eustis
Fort Gordon
Fort Hamilton
Fort Benjamin Harrison
Fort Jackson
Fort Knox
Fort Leavenworth
Fort Lee
Fort McClellan
Fort Monroe
Fort Rucker
Fort Sill
Fort Leonard Wood

INSCOM - Ch, Instl. Div.
ATTN: Facilities Engineer
Vint Hill Farms Station
Arlington Hall Station

WESTCOM
ATTN: Facilities Engineer
Fort Shafter

MDW
ATTN: Facilities Engineer
Cameron Station
Fort Lesley J. McNair
Fort Myer

HSC
HQ USAHSC, ATTN: HSLO-F
ATTN: Facilities Engineer
Fitzsimons Army Medical Center
Walter Reed Army Medical Center

USACC
ATTN: Facilities Engineer
Fort Huachuca
Fort Ritchie

MTMC
HQ, ATTN: MTMC-SA
ATTN: Facilities Engineer
Oakland Army Base
Bayonne MOT
Sunny Point MOT

US Military Academy
ATTN: Facilities Engineer
ATTN: Dept of Geography & Computer Science
ATTN: DSCPER/MAEN-A

USAES, Fort Belvoir, VA
ATTN: ATZA-DTE-EM
ATTN: ATZA-DTE-SW
ATTN: ATZA-FE
ATTN: Engr. Library

Chief Inst. Div., I&SA, Rock Island, IL

USA ARRCOM, ATTN: Dir., Instl & Svc
TARCOM, Fac. Div.
TECOM, ATTN: DRSTE-LG-F
TSARCOM, ATTN: STSAS-F
NARAD COM, ATTN: DRDNA-F
AMMRC, ATTN: DRXMR-WE

HQ, XVIII Airborne Corps and Ft. Bragg
ATTN: AFZA-FE-EE

HQ, 7th Army Training Command
ATTN: AETTG-DEH (5)

HQ USAREUR and 7th Army
ODCS/Engineer
ATTN: AEAEN-EH (4)

V Corps
ATTN: AETVDEH (5)

VII Corps
ATTN: AETSDEH (5)

21st Support Command
ATTN: AEREH (5)

US Army Berlin
ATTN: AEBA-EN (2)

US Army Southern European Task Force
ATTN: AESE-ENG (5)

US Army Installation Support Activity, Europe
ATTN: AEUES-RP

8th USA, Korea
ATTN: EAFE
Cdr, Fac Engr Act (8)
AFE, Yongsan Area
AFE, 2D Inf Div
AFE, Area II Spt Det
AFE, Cp Humphreys
AFE, Pusan
AFE, Taegu

DLA ATTN: DLA-WI

USA Japan (USARJ)
Ch, FE Div, AJEN-FE
Fac Engr (Honshu)
Fac Engr (Okinawa)

ROK/US Combined Forces Command
ATTN: EUSA-HHC-CFC/Engr

416th Engineer Command
ATTN: Facilities Engineering

Norton AFB
ATTN: AFRCE-MX/DEE

Port Hueneme, CA 93043
ATTN: Library (Code L08A)

AFESC/Engineering & Service Lab
Tyndall AFB, FL 32403

Chanute AFB, IL 61868
3345 CES/DE, Stop 27

National Guard Bureau
Installation Division
WASH DC 20310

ESD Team Distribution

HQDA (DALO-TSE-F) (3) 20310

US Army Engineer Districts (39)
ATTN: Chief, Engineer Division

US Army Engineer Divisions (15)
ATTN: Chief, Engineer Division

Army-Air Force Exchange Service 75222
ATTN: Chief, Engineering Div

Alexandria, VA 22314
ATTN: DLA-W

USA ARRADCOM 07801
ATTN: DRDAR-LCM-SP

Fort Belvoir, VA 22060
ATTN: DRDME-G
ATTN: FESA-TSO

Fort Leavenworth, KS 66027
ATTN: ATZLCA-SA

Naval Civil Engineering Laboratory 93043
ATTN: Code L03AE
ATTN: Code L60

Naval Facilities Engineering Command 22332
ATTN: Code 032E
ATTN: Code 1023
ATTN: Code 11130
ATTN: Code 044

Andrews AFB, WASH DC 20331
ATTN: AFSC-DEE

Patrick AFB, FL 32925
ATTN: XRQ

Tyndall AFB, FL 32403
ATTN: RD

Wright-Patterson AFB, OH 45433
ATTN: PDE
ATTN: PMO

Assistant Sec for Conservation & Solar Energy 20314
Assistant Sec for Resource Applications 20314
DCNO (Logistics) 20301
Director, Bldg Technology & Safety Div 20410
Director, Center for Building Technology 20234
Energy Research and Development Foundation 30037
ODAS (EE&S) 20301
DOAS (I&H) 20301
Public Building Service 20405

Department of Energy 30037
Oak Ridge, TN 37830

84
2-82

Singer, Richard J.
Conversion of Army heating plants to coal : three case studies / by R. Singer, A. Collishaw -- Champaign, IL : Construction Engineering Research Laboratory ; available from NTIS, 1982.
203 p. (Technical report / Construction Engineering Research Laboratory ; E-176)

1. Redstone Arsenal, AL. 2. Picatinny Arsenal, NJ. 3. U.S. Military Academy, West Point, NY. 4. Heating plants - conversion to coal. I. Collishaw, Anslie N. II. Title. III. Series : Technical report (Construction Engineering Research Laboratory (U.S.)) ; E-176.